DOCKETED

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Project Title:	Complaint Against the Stockton Port District re: RPS Program Compliance
TN #:	222161-7
Document Title:	Exhibit F - Stockton Port District Complaint
Description:	Staffâ€™s Evaluation of Port of Stocktonâ€™s Applied Optional Compliance Measures for the 2011-2013 Compliance Period
Filer:	Muoi-Lynn Tran
Organization:	California Energy Commission
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EXHIBIT F

STAFF'S EVALUATION OF PORT OF STOCKTON'S APPLIED OPTIONAL COMPLIANCE MEASURES FOR THE 2011-2013 COMPLIANCE PERIOD

Evaluation of the Port of Stockton's Applied Optional Compliance Measures

POU Name: Port of Stockton

Compliance Period: 2011-2013

Optional Compliance Measures Applied:

X Cost Limitation
X Delay of Timely Compliance
__Reduction of Portfolio Balance Requirements

POU Background

The Port of Stockton (Port or Stockton) is a local publicly owned electric utility (POU) that was established in 2003, and served a reported 50 end-use retail customers in 2011-2013. The Port's retail sales represent less than 0.01% of California's total retail sales of electricity in 2011-2013.

The Port incurred a shortfall in procurement and applied the cost limitation and delay of timely compliance measures to satisfy the procurement requirements for Compliance Period 1.

Application of Optional Compliance Measures

The requirements for adopting, applying, and reporting on optional compliance measures are set forth in the Energy Commission's *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (RPS POU Regulations)* as codified in the California Code of Regulations, title 20, sections 1240 and 3200 – 3208.

Materials Submitted by the Port of Stockton for Application of Optional Compliance Measures

1. Certification of the passage of the Stockton Port District Board of Commissioners Resolution #7832 on June 3, 2013, approving the Port's budget for fiscal year 2013-14
2. Renewable Portfolio Standard Procurement Plan , dated November 20, 2012 (RPS Procurement Plan)
3. Notice of December 20, 2012, public meeting to review implementation of the Port's RPS procurement plan
4. Port notice to the Energy Commission dated January 4, 2013, with final planning document for the Port's RPS procurement plan (Port Notice to Energy Commission dated January 4, 2013)
5. Narratives included with the Port's 2013 RPS compliance report, dated July 1, 2014 (Narratives)
6. Response dated August 15, 2016, to Energy Commission staff inquiry (Port Response dated August 15, 2016)
7. Supplemental narrative (Supplemental Narrative) and timeline for RPS Compliance Period 1
8. Spreadsheet of Port's RPS expenses from 2010-2015 (Expense Worksheet)
9. RPS Procurement Plan 2016 Update (Updated Procurement Plan)
10. Response dated August 17, 2017, to Energy Commission staff inquiry (Port Response dated August 17, 2017)
11. Response dated September 5, 2017, to Energy Commission staff inquiry (Port Response dated September 5, 2017)
12. Port 2012 comments on pre-rulemaking for *RPS POU Regulations* (2012 Pre-Rulemaking Comments)
13. Supporting materials for the Port's purchase of Renewable Energy Credits (RECs) for Compliance Period 1
14. Supporting materials for the CAISO cluster study required for the 20 MW solar project and subsequent delay

15. Other supporting materials for the proposed 20 MW solar project, including Port study requirements, notice to Pacific Gas and Electric Company (PG&E), and notification from the developer to cease pursuit of the project
16. Supporting materials for the required PG&E system impact studies for the 1.5-2 MW solar project
17. Other supporting materials for the proposed 1.5-2 MW solar project, including proposed funding, notice to PG&E, consultant recommendation on project cost-effectiveness, and notification to contract bidder of Port's decision to put the project on hold
18. Project proposals received by the Port and related materials, including recommendations and proposed timelines from the Port consultant
19. Other miscellaneous documents including supporting materials for the Port's REC purchases in 2014, the Energy Commission's adoption of the *RPS POU Regulations*, Port presentation on its RPS procurement plan, RPS compliance reporting forms, and reports on cost of renewables in California
20. Copy of the Stockton Port District Board of Commissioners Resolution #7681, dated August 2, 2010

Evaluation of Cost Limitation Optional Compliance Measure

Sections 3206(a)(3), 3206(b), and 3207(d)(6) of the *RPS POU Regulations* set forth the requirements for adopting and applying the cost limitation optional compliance measure. Below is a summary of the regulatory requirements for adopting and applying a cost limitation, the POU's responses to the requirements, and a staff analysis of whether the POU satisfied these requirements.

1. *The POU described the adopted cost limitation rules in its RPS procurement plan or enforcement program.* (Section 3206(b))

The Port of Stockton did not address the requirement to describe the cost limitation rules in its RPS procurement plan or an enforcement program.

The Port notified the Energy Commission on January 4, 2013, of the final planning document for its RPS procurement plan. (Port Notice to Energy Commission dated January 4, 2013, p. 1) The RPS Procurement Plan discussed the Port's current load and electricity resources planning as well as its proposed plan to meet the RPS, and delegated all enforcement of the plan to the Port's Executive Director (RPS Procurement Plan Section V, p. 10). The Port confirmed that the application of optional compliance measures was left to the discretion of the utility director. (Port Response dated September 5, 2017, p.1) The Port explained that through adoption of each fiscal year's (FY) budget, the cost limitation rules were reflected in its electric budget and rates set and approved each year by the board.

> "As a part of a two tier cost limitation rule, at the beginning of each fiscal year budget cycle, the Port reviews its prior year operating reserve and electric rate performance. Then the Port sets its electric budget and commercial/industrial rates to reflect costs and be at or below ninety---five percent (95%) of the local IOU's similar commercial/industrial rates with an operating reserve at or above 10%. Therefore, upon adoption of the FY budget the retail rates and associated cost limitations included in the budget/rate assumptions are approved by the Board for that year." (Port Response dated August 17, 2017, p.3)

However, the submitted budget documents did not identify a cost limitation. As the cost limitation measure was not formally adopted by the Port or described in its RPS Procurement Program, and the Port did not submit a separate RPS enforcement program, the requirement was not satisfied by the Port.

2. *The POU's governing board established cost limitation rules that it deemed would prevent a disproportionate rate impact.* (Section 3206(a)(3)(B)(1))

   But for the fact that the Port's cost limitation was not formally adopted, the Port addressed the requirement to establish cost limitation rules that it deemed would prevent a disproportionate rate impact.

   The Port justified its application of a cost limitation, citing depressed economic conditions, including the bankruptcy of the City of Stockton; high local unemployment; the need to attract and retain business and industry; competition with PG&E; the need to maintain operating reserves; and its small size and lack of resources. (2012 Pre-Rulemaking Comments, pp. 1, 3; Port Response dated August 17, 2017, pp. 2-3) The Port also reported sensitivity to the cost of bulk power because its load is limited to price-conscious commercial and industrial customers. (Narratives, p. 1)

   The Port further explained that its Governing Board had a long-standing policy to keep Port customer electric rates below PG&E's rates in order to meet its goals of serving as an economic driver and fostering vital employment opportunities in the region. (Port Response dated August 17, 2017, p. 2) In addition, the Port reported the need to maintain sufficient minimum operating reserves to ensure the utility could continue to operate. (Port Response dated August 17, 2017, p. 3)

   Based on these considerations, the Port's Executive Director established and implemented a cost limitation incorporating a maximum rate limit of 95 percent of PG&E's electric rates and a minimum reserve policy of 10 percent. (Port Response dated August 17, 2017, p. 3) The Port explained that the cost limitation was determined based on actual average rate performance for the prior year and the operating reserve target (Port Response dated August 17, 2017, p. 5); if the rate target was exceeded or the operating reserve target not met, the Port did not spend additional funds on RPS compliance for that year. (Port Response dated August 17, 2017, p. 3, 6)

   The Port confirmed that the cost limitation was set at a level that prevents disproportionate rate impacts, and to allow the Port to meet its minimum operating reserves. (Port Response dated August 17, 2017, p. 3)

   However, as discussed in Requirement 1 above, the Port's cost limitation rules were not formally adopted, precluding the Port from fully satisfying the requirement.

3. *The POU considered the following information when adopting its cost limitation rules:*
   - *The information in its most recent RPS procurement plan*
   - *The estimated cost of building, owning, and operating RPS eligible resources*
   - *The potential that planned resource additions may be delayed or canceled.*

   (Section 3206(a)(3)(C)(1)-(3))

   But for the fact that the Port's cost limitation was not formally adopted, the Port, through its Executive Director, addressed the requirement to rely on the most recent RPS procurement plan, the estimated cost of building, owning, and operating RPS eligible resources, and the potential that planned resource additions may be delayed or canceled, in adopting its cost limitation.

   The Port confirmed that its Executive Director relied on its RPS Procurement Plan in establishing a cost limitation, explaining that it annually incorporated ongoing implementation costs of the local proposed RPS projects into its budget and rates. (Port Response dated August 17, 2017). The Port explained that it

had received multiple estimates of the costs of renewable projects it considered developing, indicating it considered the approximate costs of building, owning, and operating eligible renewable energy resources. (Port Response dated August 15, 2016, p. 4) The Port also indicated that due to the nature of its interconnection agreement with PG&E, it considered and experienced the possibilities that planned projects may be delayed or canceled. (Port Response dated August 15, 2016, p. 4)

However, as discussed in Requirement 1, the Port's cost limitation was not formally adopted, precluding the Port from fully satisfying this requirement.

4. *The POU reported the dollar amount of the established cost limitation for the compliance period and the amount that it spent on RPS procurement during the compliance period. The POU also reported an estimate of the amount it would have needed to spend to meet the full RPS procurement requirements for the compliance period.* (Section 3207(d)(6)(A))

The Port addressed the requirement to report its cost limitation in dollars, the amount it spent on RPS procurement, and an estimate of the total cost to procure sufficient electricity products to meet its RPS procurement requirements.

The Port reported an annual cost limitation of zero dollars for each year of the compliance period, based on its evaluation of its cost limitation rules. (Port Response dated August 17, 2017, p. 6) The table below indicates how the cost limitation rules were evaluated and yielded zero dollars. If the Port's operating reserve target was met, the cost limitation in dollars is calculated by determining the rate difference between the Port's rate and the target rate and multiplying the difference by the retail kWh sales. (Port Response dated August 17, 2017, p. 5) However, if the target rate difference is not within the 95 percent target, or the Port's operating reserve target was not met, the cost limitation for the following year would be zero dollars. (Port Response dated August 17, 2017, p. 3) Based on prior year rates and operating reserves, the Port's cost limitation was zero dollars for each year of Compliance Period 1. (Port Response dated September 5, 2017, pp. 2-3)

Port of Stockton Cost Limitation Review for Compliance Period 1

	[Calendar Year 2010]	[Calendar Year 2011]	[Calendar Year 2012]	[Calendar Year 2013]
Port retail revenue ($)	$1,478,677	$1,549,425	$1,926,274	$2,216,330
Port kWh sales (kWh)	9,003,845	9,725,125	12,581,228	14,484,272
Port average retail rate ($/kWh)	$0.1642	$0.1593	$0.1531	$0.1530
Competitor average retail rate ($/kWh)	$0.1690	$0.1634	$0.1552	$0.1746
95% of competitor rate ($/kWh)	$0.1605	$0.1553	$0.1474	$0.1659
Rate difference between Port and 95% of competitor rate ($/kWh)	$0.0037*	$0.0041*	$0.0057*	$(0.0129)
Rate difference multiplied by Port's retail sales ($)	$33,258	$39,412	$71,823	$ (186,272)
Cost limitation budget ($)	n/a	$0	$0	$0
Percent off target	2.25%	2.54%	3.73%	-8.40%
Operating Reserve	2.7%	4.3%	6.9%	12.7%
*Cost limitation triggered (emphasis added by Energy Commission staff)				

Source: Energy Commission staff based on Table 4 in the Port Response dated August 17, 2017, p. 7, and Port Response dated September 5, 2017, pp. 2-3.

The Port reported total RPS expenditures of approximately $113,000 for calendar years 2011-2013, which exceeded its cost limitation. (Port Response dated August 17, 2017, pp. 4 and 6, and Expense Worksheet)

The Port estimated that it would have needed to spend a total of $414,000 to meet its full RPS procurement requirements for Compliance Period 1, or an incremental $195,000 based on the value of the REC alone. (Port Response dated August 17, 2017, p. 4)

5. *The POU applied all of its RPS procurement expenditures toward the cost limitation, and applied only those procurement expenditures permitted by its adopted cost limitation rules.* (Section 3206(a)(3)(B)(2) and 3206(a)(3)(D))

   But for the fact that the Port's cost limitation was not formally adopted, the Port addressed the requirements to ensure that the costs of all procurement credited toward achieving the RPS are counted toward the limitation and to apply only those types of procurement expenditures that are permitted under the adopted cost limitation rule.

   The Port reported approximately $113,000 of expenditures for calendar years 2011-2013 on RPS compliance. (Port Response dated August 17, 2017, pp. 4 and 6, and Expense Worksheet) In evaluating its cost limitation rules, the Port compared its actual prior year retail rates and electricity sales, which implicitly reflected the cost of all RPS procurement.

   However, as discussed in Requirement 1, the Port's cost limitation was not formally adopted, precluding the Port from fully satisfying this requirement.

6. *The POU did not apply any indirect costs, including costs for those items listed below, toward its adopted cost limitation rules:*
   - *Imbalance energy charges*
   - *Sale of excess energy*
   - *Decreased generation from existing resources*
   - *Transmission upgrades*
   - *Costs associated with relicensing any POU-owned hydroelectric facilities.*

   (Section 3206(a)(3)(B)(3))

   But for the fact that the Port's cost limitation was not formally adopted, the Port addressed the requirement that procurement expenditures applied do not include any indirect expenses. The Port stated that its reported costs did not include indirect costs associated with imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades, or the costs associated with relicensing any hydroelectric facilities. (Port Response dated August 17, 2017, p. 6)

   The Port further clarified that the 20 percent Port payroll tax, listed in the Expenditures spreadsheet, was a proxy for Port staff time spend on development, and was not considered to be an indirect cost. (Port Response dated August 17, 2017, p. 6)

   However, as discussed in Requirement 1, the Port's cost limitation was not formally adopted, precluding the Port from fully satisfying this requirement.

7. *The adopted cost limitation rules include actions the POU planned to take if it met or exceeded its cost limitation, and the POU reported on the actions it took after meeting or exceeding its cost limitation.* (Section 3206(a)(3)(E) and 3207(d)(6)(A))

   But for the fact that the Port did not formally adopt cost limitation rules, the Port addressed the requirement to report actions planned and taken in response to meeting or exceeding its cost limitation.

   The Port's cost limitation rules were designed to calculate an annual budget available for RPS spending; if the Port exceeded the cost limitation, the Port would set the budget at zero, implicitly indicating the Port planned to stop RPS expenditures after exceeding the cost limitation. (Port Response dated August 17, 2017, p. 6) Upon meeting its cost limitation after each annual evaluation in Compliance Period 1, the Port stopped spending toward meeting its RPS procurement requirements, consistent with its rules. (Port Response dated August 17, 2017, p. 6)

   However, as discussed in Requirement 1, the Port's cost limitation was not formally adopted, precluding the Port from fully satisfying this requirement.

Evaluation of Delay of Timely Compliance Optional Compliance Measure

Sections 3206(a)(2), 3206(b), and 3207(d)(6) of the *RPS POU Regulations* set forth the requirements for adopting and applying the delay of timely compliance measure.

The Port indicated that "permitting, interconnection, or other circumstances have delayed procured eligible renewable energy resource projects, or there is an insufficient supply of eligible renewable energy resources available to the POU" caused a delay in timely compliance with the Compliance Period 1 procurement requirements, pursuant to section 3206(a)(2)(A)(2) of the *RPS POU Regulations*.

Below is a summary of the regulatory requirements for adopting and applying the delay of timely compliance measure, the POU's responses to the requirements, and a staff analysis of whether the POU satisfied these requirements.

1. *The POU described the adopted delay of timely compliance measure in its RPS procurement plan or enforcement program.* (Section 3206(b))

   The Port did not meet the requirement to describe the delay of timely compliance measure in its RPS procurement plan or enforcement program.

   The Port notified the Energy Commission on January 4, 2013, of the final planning document for its RPS procurement plan (Port Notice to Energy Commission dated January 4, 2013, p. 1). The RPS Procurement Plan discussed the Port's current load and electricity resources planning as well as its proposed plan to meet the RPS, and delegated all enforcement of the plan to the Port's Executive Director. (RPS Procurement Plan Section V, p. 10) The Port also confirmed that the application of optional compliance measures was left to the discretion of the utility director. (Port Response dated September 1, 2017, p.1)

   However, the delay of timely compliance measure was not adopted by the Port or described in the Port's RPS Procurement Plan, and the Port did not submit a separate RPS enforcement program. Therefore, the requirements of section 3206(b) were not satisfied.

Evaluation: Port of Stockton

2. *The POU demonstrated that it would have satisfied its RPS procurement requirements if it had not encountered the delay.* (Section 3206(a)(2)(A))

The Port addressed the requirement to demonstrate that it would have met its RPS procurement requirements but for the cause of delay.

The Port reported entering into a development agreement in 2010 to purchase renewable energy from a proposed 20 MW rooftop solar facility located on the Port's warehouse facilities. (Updated RPS Procurement Plan, p. 3) The proposed project would have sold power to both PG&E and the Port, as the output was more than seven times the size of the Port's total retail load. (Updated RPS Procurement Plan, p. 3) The Port anticipated that the project would be fast tracked and operational by late 2011. (Port Response dated August 17, 2017, p. 1)

The 20 MW project required a System Impact Study (SIS) performed by PG&E in conjunction with CAISO, which was initiated by the Port in November 2010. (Updated RPS Procurement Plan, p. 3) However, the Port reported that the project "fell into an area of a transmission user not addressed in the CAISO tariff," and CAISO would not include the project in its transmission cluster study because it did not fit the parameters of its transmission tariff. (Port Response dated August 17, 2017, pp. 1-2) The Port further reported that after multiple cluster study issues with PG&E and the CAISO and due to overall project costs, the developer abandoned the project. (Updated RPS Procurement Plan, p. 3)

The Port had anticipated an output of over 70,000 megawatt hours (MWh) from the 20 MW solar project during Compliance Period 1, significantly more than its RPS procurement target of 7,357 MWh, as stated in the *Renewables Portfolio Standard Verification Results: Port of Stockton, Compliance Period 1* report, adopted by the Energy Commission on January 25, 2017. (Port Response dated August 17, 2017, p. 1) Furthermore, the Port stated that it intended to purchase sufficient amounts from the project to meet the RPS procurement requirements. (Updated RPS Procurement Plan, p. 3) However, due to circumstances beyond the Port's control, the development was delayed and could not be completed.

The Port responded to the 20 MW project cancellation by pursuing a smaller, "right-sized" project. (Port Response dated August 17, 2017, p. 2) In November 2012, the Port issued a revised RPS procurement plan focusing on the development of a 1.5–2 MW local solar project that would produce 2,500 MWh of portfolio content category (PCC) 1 electricity products, and the output of which the Port would supplement with the purchase of unbundled RECs. (Port Response dated August 17, 2017, p. 2) However, according to the Port, a new SIS was required for the proposed smaller solar project pursuant to the terms of the Port's interconnection agreement with PG&E. (Updated Procurement Plan, p. 3) The Port reported that it requested and paid PG&E for the SIS on January 3, 2013, but the study was not completed until January 2014. (Updated RPS Procurement Plan pp. 3-4) Upon completion of the study, which found no significant impacts, the Port reevaluated the cost effectiveness of the project compared to other renewable market options for RPS compliance and suspended the project in favor of purchasing electricity from RPS-certified generation in 2017. (Updated RPS Procurement Plan, pp. 3-4; Narratives, p. 4)

In summary, the Port anticipated that the 20 MW solar project would provide sufficient electricity products to meet its full RPS procurement requirements; however, due to circumstances beyond its control, the project was cancelled. The Port then pursued a smaller, 1.5 – 2 MW solar project, the output of which it intended to supplement with REC purchases, but this project, too, was delayed for reasons beyond the Port's control and ultimately suspended in favor of more cost-effective options.

Evaluation: Port of Stockton

3. *The POU prudently managed portfolio risks, including:*
   - *Holding solicitations for RPS-eligible resources*
   - *Relying on a sufficient number of projects the POU considered viable for meeting the RPS procurement requirement.*

   (Section 3206(a)(2)(A)(2)(i))

   The Port addressed the requirement to prudently manage portfolio risks, including but not limited to holding solicitations and relying on a sufficient number of viable projects to achieve the RPS procurement requirements.

   As discussed in Requirement 2, the Port anticipated that the 20 MW solar project was viable and the output would fully satisfy its RPS procurement requirements. (Updated RPS Procurement Plan, p. 3) However, due to circumstances beyond the Port's control, including a delayed system impact study conducted by PG&E and the project's exclusion from a CAISO cluster study required pursuant to the Port's interconnection agreement with PG&E, the project fell through. (Updated RPS Procurement Plan, p. 3; RPS Procurement Plan Section III, pp. 5-6)

   The Port then sought new projects to meet its RPS procurement requirements, indicating it solicited offers for RPS-eligible resources. The Port considered multiple proposals for developing or purchasing the output from eligible renewable energy resources, including roof- and ground- mounted solar systems ranging from 0.5–2 MW in size and a large biomass facility. (Supplemental Narrative, pp. 3-4; Narratives, p. 2, 4)

   The Port ultimately pursued development of a smaller 1-2 MW local solar project, the output of which it intended to supplement with REC purchases (Port Response dated August 17, 2017, p. 2); however, after encountering schedule delays and reevaluating the project's cost-effectiveness, the Port suspended project development, as discussed in Requirement 2 above.

4. *The POU sought to develop at least one of the following:*
   - *Its own RPS-eligible resources*
   - *Transmission to interconnect to RPS-eligible resources*
   - *Energy storage used to integrate RPS-eligible resources.*

   (Section 3206(a)(2)(A)(2)(ii))

   The Port addressed the requirement to seek to develop either its own RPS-eligible resources, transmission to connect to RPS-eligible resources, or energy storage used to integrate RPS-eligible resources.

   The Port demonstrated efforts to develop its own renewable energy resources, which included reviewing multiple proposals for utility-owned generation. (Port Response dated August 17, 2017, p. 2; Supplemental Narrative, pp. 3-4) The Port pursued development of a 1.5 MW PV project, including completing the system impact studies required by PG&E. (Port Response dated August 17, 2017, p. 2; RPS Procurement Plan Section V, p. 10) However, study-related delays set back the project and the Port ultimately found it would no longer be cost-effective. (Updated RPS Procurement Plan, pp. 3-4; Narratives, p. 4)

5. *The POU procured at a level above its RPS requirements to compensate for foreseeable delays or insufficient supply.* (Section 3206(a)(2)(A)(2)(iii))

The Port addressed the requirement to procure an appropriate minimum margin above the level necessary to comply with the RPS to compensate for foreseeable delays or insufficient supply.

As discussed in Requirement 2 above, the Port could not have reasonably foreseen the exclusion of its 20 MW solar project, with which it anticipated it could satisfy the entirety of its RPS procurement requirements. (Port Response dated August 17, 2017, pp. 1-2) Thus, it is appropriate that the Port did not attempt to procure additional resources above the level necessary to comply with the RPS.

Furthermore, the Port attempted to make up for part of the lost generation by pursuing a smaller 1-2 MW project. (RPS Procurement Plan Section V, p. 10) However, this project was also delayed due to changes to the scope of the system impact study required by PG&E, which was unforeseen and outside of the Port's control. (Narratives, p. 4)

6. *The POU took reasonable measures to procure cost-effective distributed generation and allowable unbundled RECs.* (Section 3206(a)(2)(A)(2)(iv))

The Port addressed the requirement to take reasonable measures to procure cost-effective distributed generation and allowable unbundled RECs.

The Port reported receiving multiple proposals for renewable energy facilities located at the Port facilities, including a 500 kW solar rooftop system and 1.5 MW ground based solar project. (Supplemental Narrative, pp. 3-4) The Port indicated that it sought to develop cost-effective distributed generation through the local renewable projects described in its RPS procurement plans, including the 1.5 MW ground based solar project, but ultimately determined that these projects were not cost-effective. (RPS Procurement Plan Section V, p. 10; Port Response dated September 5, 2017, p. 1)

The Port sought to obtain and did procure unbundled RECs, as confirmed in its *Renewables Portfolio Standard Verification Results: Port of Stockton, Compliance Period 1* Report. (Supplemental Narrative, p. 4) The Port stated that the quantity of RECs purchased in 2012 was reflective of its PCC3 balance requirement, based on the soft target in 2012. (Narratives, p. 3) The Port did not explain why it did not seek to procure additional unbundled RECs beyond the PCC 3 balance limitation for the 2012 soft target. However, it is a reasonable conclusion that the Port procured a limited amount of unbundled RECs, because, as it retired no PCC 1 or 2 RECs, only 25 percent of unbundled RECs retired would be allowable for compliance.

Escobar, Steve

To: Escobar, Steve
Subject: RE: WAPA contract

From: Ishimoto, Yvonne
Sent: Tuesday, July 31, 2012 3:33 PM
To: Dias, Janice
Cc: Villanueva, Juan; Aschieris, Richard
Subject: FW: Request for Copy of Resolution #7681

STOCKTON PORT DISTRICT
Board of Port Commissioners
Minutes
August 2, 2010

CONSIDERATION AND POSSIBLE AUTHORIZATION
FOR PORT DIRECTOR TO EXECUTE CONTRACT
FOR PURCHASE OF ELECTRICAL POWER

Resolution #7681: WHEREAS, the Stockton Port District (Port) is a public corporation created for municipal purposes pursuant to Section 6290 of the California Harbors and Navigation Code; and

WHEREAS, the Port owns and maintains the utility system infrastructure, including power lines and poles, located on Rough & Ready Island which is also known as the West Complex; and

WHEREAS, the Pacific Gas and Electric Company (PG&E) provides electricity to the West Complex pursuant to an industrial tariff; and

WHEREAS, due to a request by the Port, PG&E filed with the Federal Energy Regulatory Commission (FERC) a request to provide only transmission and interconnection services to the Port to serve the West Complex and allow the Port to provide an independent power supplier; and

WHEREAS, the costs of electricity fluctuate daily; now, therefore be it

RESOLVED, that the Board of Port Commissioners of the Stockton Port District hereby authorizes the Port Director to enter into an Electrical Service Provision Agreement; and

RESOLVED FURTHER, that the Port Director is hereby authorized to establish, set and charge rates for the delivery of power to tenants on Rough and Ready Island; and

RESOLVED FURTHER, that the Chairman of the Board of Port Commissioners and/or the Port Director are hereby authorized, empowered and directed to ensure that the provisions of this resolution are appropriately effected.

From: Dias, Janice
Sent: Monday, July 30, 2012 9:42 AM
To: Ishimoto, Yvonne
Cc: Villanueva, Juan
Subject: Request for Copy of Resolution

Yvonne,
Juan is requesting a copy of the Resolution from the August 2, 2010, Commission Meeting approving "Contracting for 2011 Power Supply."

Thank you,

Janice Dias
Administrative Assistant I
Port of Stockton
(209)946-0246
jdias@stocktonport.com

PORT OF STOCKTON

Phone: (209)946-0246

Fax: (209) 466-5984

Certification

I, Melanie Rodriguez, Interim Secretary of the Stockton Port District, do hereby certify that the following is a full, true, and correct copy of Resolution #7832 of the Board of Port Commissioners of the Stockton Port District, as passed at a regular meeting held on the 3rd day of June 2013, and that said resolution is in full force and effect:

> RESOLVED, by the Board of Commissioners of the Stockton Port District that the budget for fiscal year 2013/2014, a copy of which is on file with the Secretary, be and it is hereby adopted.

Dated this 7th of September 2017

Melanie Rodriguez, Interim Secretary

Port of Stockton

Renewable Portfolio Standard Procurement Plan

California Energy Commission 33% RPS Regulation

11/20/2012

Port of Stockton
Renewable Portfolio Standard Procurement Plan

I. Executive Summary

In 2008 Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring the state's electric utilities to achieve an electric generating portfolio that supplies electricity from 33% renewable resources by 2020. Subsequently, Governor Brown signed Senate Bill X1-2 that specified a timetable with compliance periods leading up to the 33% by 2020 and charged the California Energy Commission (CEC) with enforcement through the California Air Resources Board.

The legislation was codified in the Public Utilities Code and an implementing 33% Renewable Resource Portfolio Standard (RPS) Regulation is under review by the CEC. It applies to all utilities in California and requires that the publically owned utilities develop a plan for renewable resource procurement and conduct a public hearing on the plan by January 1, 2013.

The Port of Stockton Staff has been investigating the incorporation of renewable resources into its supply portfolio since 2010. Staff in conjunction with a developer, did identify a project involving construction of 15,000 kilowatts of photovoltaic generating arrays on the roofs of 30 of the Port's warehouses on Rough & Ready Island. While the Port would purchase only the amount of power necessary to meet its requirements under the RPS the balance of the power was anticipated to be delivered to PG&E under one of its' PV Requests for Bids. The project was defined and an estimate of its costs developed resulting in an average cost of $0.14/kWh. Unfortunately, the developer was unsuccessful in its attempt to sell the output to PG&E.

Since that project the Port staff has been monitoring the development of the CEC RPS Regulation. In addition, the cost of photovoltaic power generation has come down significantly due to competition in the solar panel market. In order to meet the RPS requirements the Port staff proposes to utilize Renewable Energy Certificates (RECs) in 2013 and 2014 while at the same time undertaking the construction of a 1,500 kW solar power plant. This will enable the Port to meet the 20% renewable resource requirement in 2014 while minimizing the impacts on the economics of the Port's electric power supply.

The cost of renewable electricity supply is more than conventional supply. However, the impact on the Port's costs and ultimately electric rates, is somewhat mitigated through load growth. It is anticipate that the potential increase in power supply costs may be less than 10% and allow the Port to remain rate competitive with its' nearby investor owned utility.

II. Regulatory History and Requirement[1]

Following is the summary provided by the California Energy Commission regarding the history of the Renewable Portfolio Standard.

Established in 2002 under Senate Bill 1078, California's Renewables Portfolio Standard (RPS) was accelerated in 2006 under Senate Bill 107 by requiring that 20 percent of electricity retail sales be served by renewable energy resources[2] by 2010. Subsequent recommendations in California energy policy reports advocated a goal of 33 percent by 2020, and on November 17, 2008, Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring that "...[a]ll retail sellers of electricity shall serve 33 percent of their load with renewable energy by 2020." The following year, Executive Order S-21-09 directed the California Air Resources Board, under its Assembly Bill 32 authority, to enact regulations to achieve the goal of 33 percent renewables by 2020.

In the ongoing effort to codify the ambitious 33 percent by 2020 goal, Senate Bill X1-2 was signed by Governor Edmund G. Brown, Jr., in April 2011. This new RPS preempts the California Air Resources Boards' 33 percent Renewable Electricity Standard and applies to all electricity retailers in the state including publicly owned utilities (POUs), investor-owned utilities, electricity service providers, and community choice aggregators. All of these entities must adopt the new RPS goals of 20 percent of retails sales from renewables by the end of 2013, 25 percent by the end of 2016, and the 33 percent requirement being met by the end of 2020.

The Energy Commission and the California Public Utilities Commission work collaboratively to implement the RPS. The original RPS legislation assigned the Energy Commission with the following responsibilities:

- Certify renewable facilities as eligible for the RPS.
- Design and implement a tracking and verification system to ensure that renewable energy output is counted only once for the purpose of the RPS and for verifying retail product claims in California or other states.

Senate Bill X1-2 increased the Energy Commission's role with responsibilities specific to publicly owned utilities:

- Directs the Energy Commission to adopt regulations specifying procedures for enforcement of the RPS for publicly owned utilities.

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[1] Source: California Energy Commission Website, Renewable Portfolio Standards (RPS) Proceeding Docket # 11-RPS-01 and 03-RPS-1078 discussion.

[2] "Renewable electrical generation facility" means a facility that uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology. Public Resources Code 25741 (a) 1.

- Requires the Energy Commission to certify and verify eligible renewable energy resources procured by publicly owned utilities and to monitor their compliance with the RPS. The Energy Commission will continue to certify and verify RPS procurements by retail sellers.
- The Energy Commission refers the failure of a publicly owned utility to comply, to the Air Resources Board, which may impose penalties.

Implementation of the Renewable Portfolio Standard is accomplished through the Public Utilities Code.[3] During 2012 the California Energy Commission has been conducting a rule-making to codify the requirements of the Public Utilities Code into regulations. The regulations are scheduled for adoption by the Commission mid-February 2013.[4] The Public Utilities Code and the draft regulations[5] were used to specify the detail assumptions of the implementation plan included in this document.

There are not only requirements as to the percent of retail sales to be supplied from renewable resources but also the type/location of renewable resource and use of Renewable Energy Certificates[6]. Table 1 summarizes the required amount of renewable resources as a percent of retail electricity sales and the amount of three types of Portfolio Content Categories.

Compliance Period	**1/1/11-12/31/13**	**1/1/14-12/31/15**	**1/1/16-12/31/19**	**1/1/20 and Beyond**
RPS Percent of Retail Sales	20%	20%	25%	33%
Portfolio Content Category 1	>50%	>65%	>75%	=>75%
Portfolio Content Category 2				
Portfolio Content Category 3	<25%	<15%	<10%	=<10%

Table 1 - RPS Requirements

Portfolio Content Category 1 resource is one that is connected to the Western States grid (preferably within California) and whose power is delivered as generated in time and quantity.
Portfolio Content Category 2 resources are those that are also connected to the Western States grid but are delivered by an intermediary with "balancing and shaping" energy.

[3] Public Utilities Code Division 1. Regulation of Public Utilities, Part 1. Public Utilities Act, Chapter 2.3. Electrical Restructuring, Article 16. California Renewables Portfolio Standard Program Section 399.11 - 399.31.
[4] 33% Draft Regulations For Publically Owned Utilities, Angie Gould, California Energy Commission, July 30, 2012.
[5] 33 Percent Renewables Portfolio Standard Pre-Rulemaking Draft Regulations, CEC-300-2012-001-SD2, California Energy Commission, July 2012
[6] A Renewable Energy Certificate (REC) represents the property rights to the environmental, social, and other nonpower qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source. One REC equals 1,000 kWh.

Portfolio Content Category 3 are Renewable Energy Certificates (RECs) that represents the property rights to the environmental, social, and other non-power qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source. One REC equals 1,000 kWhs.

III. Historical Renewable Resource Planning Activities

The Port of Stockton's retail electric system has been in operation since May of 2003. At that time the Port took over the Rough & Ready Island Naval Ship Repair Facility and the existing electric distribution system. Retail electric sales were on average a little less than 300,000 kWh's month. In 2008 sales had grown to in excess of 800,000 kWhs per month. See Figure 1.

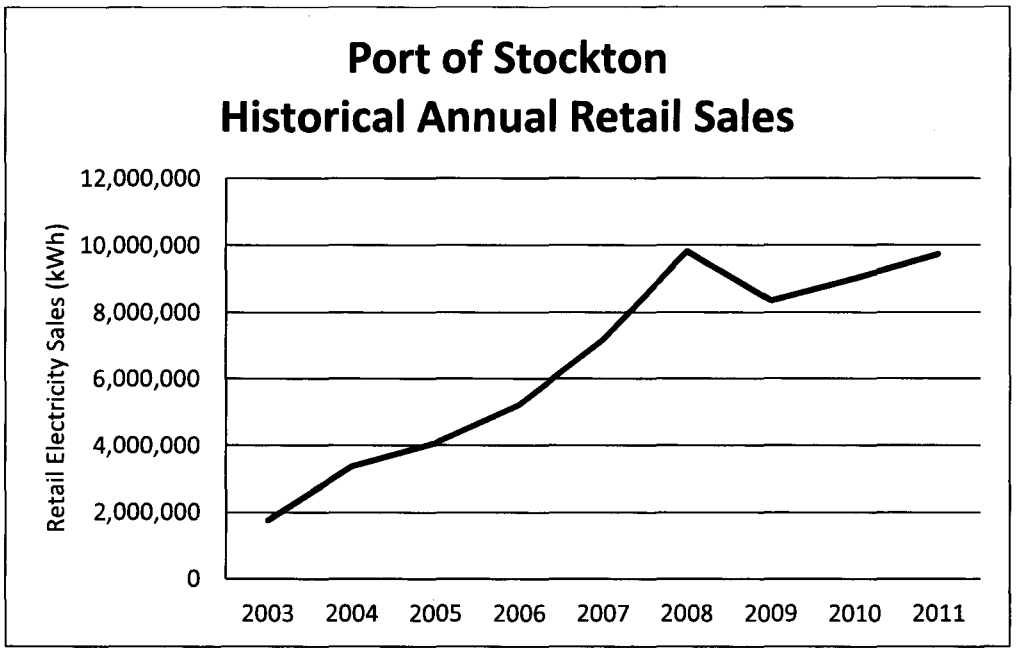

Figure 1 – Historical Annual Retail Electricity Sales

During 2009 and 2010 the Port's retail electric sales dropped significantly due to the turn down in the economy. However, in late 2010 and 2011 the sales started to rebound. Because of the poor economy, 2009 through the first half of 2011 operations resulted in reduced electricity sales and significant stress on the Port's electric utility financials. During this period, the Port's retail electric rates were slightly under the nearby investor owned utility. The combination of the turndown in the economy and the need for competitive rates resulted in constraints being placed on utility expenses to remain competitive while addressing the reduced retail sales.

Its electricity supply was provided by one supplier from 2003 through May of 2011 under a fixed price, full requirements, and electricity contract. In early 2011 the Port of Stockton staff explored options to meet the requirements of the Renewable Portfolio Standard. At that time the price of wholesale electricity under its contract was approximately

$0.088/kWh[7]. Including all other capital and utility expenses the average cost of service was approximately $0.16/kWh[8]. Table 2 compares the Port's commercial and industrial electricity rates to the nearby investor owned utility's retail electricity rates.

Port of Stockton Retail Rate Schedule	Average Rate/kWh	PG&E Retail Rate Schedule	Average Rate/kWh
GS-1	$0.1711	A-1	$0.17952
GS-2	$0.1572	A-10	$0.15818
GS-3	$0.1365		

Table 2 - January 2011 Port of Stockton/PG&E Average Rates[9]

The Port staff recognized the competitive pressure of the surrounding utility and controlled costs under its existing cost structure to continue to provide competitive rates.

During 2010 and 2011 Port staff was working with a renewable developer to construct a utility scale, roof mounted, 15-20 MW photovoltaic system. The system would make use of approximately 30 of the warehouse roofs on Rough & Ready Island to host PV arrays that would produce renewable electric energy. The Port, in conjunction with the developer had completed the PG&E required System Impact Study as well as some preliminary work with the California Independent System Operator. The project concept involved constructing the PV system, transmitting a majority portion of the power through the Port's electric system to its interconnection with PG&E where the developer would sell the remaining output to another party. The Port would participate in the project to the extent necessary to meet the requirements of the Renewable Portfolio Standard.

By April 2011 much of the planning work necessary to develop a project cost estimate had been completed. In an April 15, 2011 letter to the Port the developer advised the Port that the cost of the project would require a payment of approximately $140/MWHR ($0.14/kWh) to go forward.[10] Including this cost in the Port's cost structure would require a rate increase pushing the Port's retail rate in excess of PG&E's thereby making the Port non-competitive with PG&E. In addition, the CAISO had determined that it required a major Deliverability Study to determine the impact on the transmission system within the Stockton Area and that could not be accomplished during 2011. The developer also participated in the PG&E PV solicitation without success. The cost issues as well as the failure to have PG&E accept the Rough & Ready Solar Project in the bid process resulted in the developer stopping the

[7] January 2011
[8] FY 2010-11 Budget.
[9] Port of Stockton Average Billing Rate Accounting Electric Summary Billing and PG&E January 1, 2011 to February 28, 2011 "PG&E Bundled Commercial/General Service Electric Rates at a Glance".
[10] April 15, 2011 Letter to Jeff Kaspar from Richard Zahner, Rough & Ready Solar LLC.

project. The Port had to regroup to determine a better course of action to address the RPS requirements.

IV. Current Load and Electricity Resources Planning

As part of the Port of Stockton's resource planning and budgeting it prepares an annual five year load forecast. This load forecast is limited to just five years because of the volatility of the load. It has no residential customers, only commercial and industrial. Its total maximum demand is approaching 4 MW during 2012. It regularly receives inquiries from potential tenants that have loads that are in excess of the Port's existing load. For this reason longer term planning presents some risks in the acquisition of electricity supplies that ultimately may not be utilized. The Port's history and 2013-2017 load forecast is shown in Figure 2.

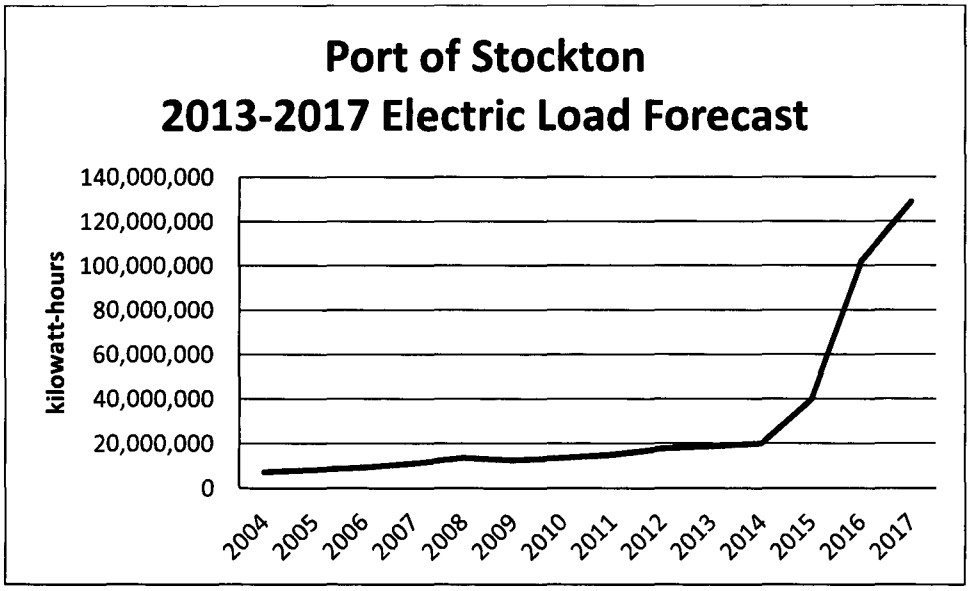

Figure 2 - Port of Stockton Historical and Forecasted Electric Loads

The electric load is forecast to increase substantially in 2015 through 2017. There are two major tenants that have agreements with the Port to site their facilities there. However, they typically reserve the right to change their plans. Although there is some risk and costs to the potential tenant to delay their expansion at the Port there is always a possibility that they will not go forward. For this reason the Port is recommending a short planning horizon for expansion of their electrical power supply. In establishing a course of action for complying with the Renewable Resource Portfolio Standard it will be considering options for meeting the 2013 and 2014 requirements. This is for the established load already existing at the Port's facilities on Rough & Ready Island with a minor amount of growth.

Options for supplying the Port's total electrical load include its existing supplier contract for power supply, other electrical power suppliers, a small allocation of Western Area Power Administration Central Valley Power starting in 2015, and the construction of a PV

generating project or other technology as previously contemplated only on a smaller scale. The mix of resources selected will include consideration of RPS requirements.

RPS requirements involve a percentage of retail sales being met from renewable resources, the type and location of renewable resources (described in the draft Regulation as Portfolio Content Categories) and the purchase of Renewable Energy Certificates (RECs)[11]. Table 3 lists the resources and the limitations on how renewable resources can meet the RPS.

	Forecast				
	2013	**2014**	**2015**	**2016**	**2017**
System Input	18,649,695	19,881,073	39,568,694	101,692,068	128,757,909
Losses	1,305,479	1,391,675	2,769,809	7,118,445	9,013,054
Load at Meter	17,344,216	18,489,397	36,798,885	94,573,623	119,744,856
Internal Port Load	5,203,265	5,546,819	6,000,000	6,500,000	7,000,000
Retail Sales	12,140,951	12,942,578	30,798,885	88,073,623	112,744,856
RPS % of Sales[12]	**20.0%**	**20.0%**	**20.0%**	**25.0%**	**25.0%**
RPS Energy Requirement	2,428,190	2,588,516	6,159,777	22,018,406	28,186,214
Unbundled REC %[13]	25.0%	15.0%	15.0%	15.0%	10.0%
REC Energy	607,048	388,277	923,967	3,302,761	2,818,621
Number of RECs	607	388	924	3,303	2,819
Remaining RPS Generation Req.	1,821,143	2,200,238	5,235,811	18,715,645	25,367,593
RPS PV Energy Plant Factor[14]	0.19	0.19	0.19	0.19	0.19
RPS Solar Capacity (kW)	**1,094**	**1,322**	**3,146**	**11,245**	**15,241**

Table 3 - Determination of Renewable Resource Requirements

Table 3 combines the load forecast with a calculation of the amount of renewable energy required as specified by the draft RPS Regulation as well as an estimate of the amount of RECs and RPS Solar Capacity necessary to meet the 20% renewable requirement in 2013 and 2014. RECs will be used in the year purchased for as long as the retail load meets the forecast otherwise carried forward for the life of the REC (3 years). RECs will be retired in the year used.

From the load forecast and resource options costs can be determined for budget and financial impact on the system. Table 4 provides a buildup of the components of the Port's power supply costs.

[11] A REC (pronounced: rĕk) represents the property rights to the environmental, social, and other nonpower qualities of renewable electricity generation. A REC, and its associated attributes and benefits, can be sold separately from the underlying physical electricity associated with a renewable-based generation source.
[12] July 2012 Draft RPS Regulation, CEC, Section 3204(a)(2).
[13] July 2012 Draft RPS Regulation, CEC, Section 3204(c)(5 and 6).
[14] Typical Plant Factor for a photovoltaic plant operating in the Central California area.

Purchase Power		**2013**	**2014**
System Input (kWh)		18,649,695	19,881,073
Contract Energy (kWh)		14,937,600	14,980,000
Contract Power ($)		$758,950	$814,381
PV Plant Energy	0.19		2,496,600
Annual Cost of PV Plant			$285,227
Additional Energy (kWh)		3,712,095	2,404,473
Cost of Additional Energy ($)		$144,772	$98,463
Demand (kW-Mo.)		45,254	49,359
Resource Adequacy Cost ($+15%)		$156,126	$178,803
Energy at Meter (Losses = 7%)		17,344,216	18,489,398
Internal Port Load	30.00%	5,203,265	5,546,819
Retail Sales		12,140,951	12,942,579
RPS Requirement (%)		20%	20%
RPS Energy Required (kWh)		2,428,190	2,588,516
Less POS Renewable Resources		0	2,496,600
REC Energy Needed		**2,428,190**	**91,916**
Maximum RECs % of RPS Req.		25%	15%
REC Energy		607,048	388,277
MAX RECs (1 REC=1,000 kWh)		607	388
RECs Required		607	388
RPS RECs Cost[15]		$911	$679
CAISO Charges		$332,524	$372,204
Monthly Service Fee		$18,000	$18,000
Total Power Supply Cost		$1,411,283	$1,772,171
Average Cost/ kWh		$0.07567	$0.08914
Renewable Resource Cost			
1. PV Plant			
a. Size (kW)			1,500
b. Capital Cost +10%			$1,815,000
c. Annual Debt Service (20 yr.)	5.00%		$145,640
d. O&M ($/kW)[16]	$96		$144,000
e. Total Annual Cost			$289,640
f. Cost/kWh			$0.1160

Table 4 - Cost of the Power Supply to Meet the Port Electric Load.

Table 4 provides the cost of the power supply in 2013 and 2014 necessary to meet the load including Resource Adequacy capacity, the cost of RECs where usable and the estimated cost of the 1,500 kW PV power plant. The Port's engineer's initial estimate of the capital

[15] Based on November 19, 2012 proposal from Shell Energy NA for 2013/14 RECs.
[16] National Renewable Energy Laboratory, NREL/SR-6A20-48595, November 2010, page 116, escalated to 2012.

cost of photovoltaic power plant to be $1,650,000.[17] Annual cost of debt service and operation and maintenance is anticipated to be less than $300,000. The average cost of total supply increases due to the higher incremental cost of the photovoltaic power plant.

Incorporation of the photovoltaic power plant and the cost of RECs increase the 2014 average power supply costs by approximately $0.009/kWh or 12%. This is mainly due to the incorporation of the photovoltaic power plant with an average cost of approximately $0.11/kWh plus the cost of RECs.

Although the increase in power supply costs raises the overall costs for the utility, load growth tends to mitigate the impact on the system operating costs and thus retail rates. There are also increases in contract costs and the overall cost of additional power the Port will need. The overall increase in retail rates is anticipated to less than 10%. This is due to averaging of the relatively stable other costs of existing interest, distribution system operation and maintenance, and administrative and general expenses.

As the Port's staff works through the process of implementing the RPS Procurement Plan there may be changes in factors influencing the outcome. Any changes in the plan will be reviewed by the Port's staff and submitted to the California Energy Commission.

[17] HCS Engineering, May 31, 2012 draft proposal for engineering services.

V. Proposed Plan

In order to address the need to meet the Renewable Resource Portfolio Standard the Port of Stockton is proposing to meet the first compliance period target through a combination of Renewable Energy Certificates and the construction of a utility owned 1,500 kW Photovoltaic Power Plant. In 2013 and 2014 the Port will expend substantial funds to design and construct the power plant while purchasing the maximum allowable Renewable Energy Certificates. In order to use RECs the Port will have to join the Western Renewable Energy Geographic Information System.[18]

In 2014 it is anticipated that it will meet the 20% retail sales requirement target through this strategy. As the cost and the impacts of the change in supply and load growth become better known the change in the electric system revenue requirement and its impact on retail rates can be better understood and acted on. Table 6 compares the Port's current rates to PG&E's current rates.

Port of Stockton Retail Rate Schedule	**Average Rate/kWh**	**PG&E Retail Rate Schedule**	**Average Rate/kWh**
GS-1	$0.1711	A-1	$0.18531
GS-2	$0.1572	A-10	$0.15876
GS-3	$0.1365		

Table 6 - July 2012 Port of Stockton/PG&E Average Rates[19]

The difference between the Port's GS-1 and PG&E's A-1 average rate is approximately 8.3% with PG&E being higher.

Alternatives to this plan involve researching available renewable resource projects outside the Port's local system boundary and attempting to negotiate a position in that resource. In addition, resources outside the Port's system will require use of the CAISO's transmission system and the attendant costs and operational requirements.

Enforcement of this plan is accomplished through action by the Port's Executive Director to require staff to proceed with its implementation and necessary steps to meet the RPS.

[18] In order to use RECs the Port will have to join the Western Renewable Energy Geographic Identification System (WREGIS). The Western Renewable Energy Generation Information System is a database designed to track all renewable energy generation in the geographic area of the Western states. Participating in the WREGIS has an annual fee of $1,500 plus a charge of $0.005 to $0.01/REC when issued, transferred or retired.

[19] Port of Stockton Average Billing Rate Accounting Electric Summary Billing and PG&E July 1, 2012 to Present "PG&E Bundled Commercial/General Service Electric Rates at a Glance".

Port of Stockton
2201 West Washington Street
P.O. Box 2089
Stockton, CA 95201

Public Notice

Renewable Resource Procurement Plan

Notice is hereby given that the Port of Stockton will be conducting a public meeting to review implementation of a Renewable Resource Procurement Plan. The public meeting will be conducted on:

Thursday, December 20, 2012, at 10:00 AM
At the
Portside Room
2303 West Washington Street,
Stockton, California

The Port of Stockton has prepared a draft plan for the procurement of renewable electric energy generating assets and other assets necessary to meet the State of California's Renewable Portfolio Standard. This Standard requires the Port to provide 33% of its electricity supply for retail sales from renewable resources such as biomass, solar, wind, and geothermal generating resources by 2020. The Renewable Resource Procurement Plan has been developed to establish a strategy and schedule, consistent with the Renewable Resources Standard for its implementation. This public meeting will provide the Port's customers with an opportunity to ask questions and provide comments.

A paper or electronic copy of the plan can be obtained from Janice Dias by calling her at (209) 946-0246.

PORT OF STOCKTON

Phone: (209) 946-0246

Fax: (209) 465-7244

January 4, 2013

Ms. Angela Gould, Energy Commission Specialist II
Renewable Energy Office
California Energy Commission
1516 9th St., MS-45
Sacramento, CA 95814-5512

Dear Ms. Gould,

Attached is the final planning document for the Port of Stockton's RPS Procurement Plan. The Port's staff conducted a public meeting to discuss its procurement strategy and plan on December 20, 2012. Notice was provided to its customers on Rough & Ready Island at the beginning of December. Comments on the draft Procurement Plan were received ahead of and during the meeting. The Port has considered those comments and incorporated them into its planning where appropriate.

Attached is the final RPS Procurement Plan dated December 31, 2012. We will also email electronic copies of the plan to you and Ms. Lorraine Gonzalves. Should you have any questions please feel free to contact me at (209) 946-0246 or Chris Kiriakou at (209) 634-8105.

Sincerely,

Juan G. Villanueva
Projects & Contract Administration/DBELO Manager

cc: Steve Escobar

Port of Stockton
Compliance Report Form for POUs
2011-13 Narratives

Introduction

The Stockton Port District owns and operated an electric utility located on Rough & Ready Island at Stockton, California. The utility has over 50 commercial and industrial customers with no residential customers having a coincident demand of approximately 4 MW and consuming over 14,400 MWhs. The distribution system is interconnected to the PG&E 60 kV system at Rough & Ready Island utilizing the Port's 60 kV to 12 kV distribution substation. Because the Port's load is limited to commercial and industrial customers, who are price conscious, the Port has been particularly sensitive to the cost of bulk power.

Annual Public Goods Funds Collected and Expended

The Port of Stockton collects the Public Goods Charge through its retail billing. The following Table 1 indicates the amounts collected and expended during 2011, 2012, and 2013.

Table 1 - Public Goods Funds			
	2011	**2012**	**2013**
Annual Funds Collected	$43,860	$56,741	$64,963
Expenditures	$50,085	$22,759	$23,232
Results	See Narrative below	See Narrative below	See Narrative below

During 2010 $6,183 was expended on a photovoltaic project investigation.

2011 Activities and Results

In 2011 the Port entered into an agreement with Solar Power Partners Inc. of Mill Valley, California to study the construction and interconnection of a 17 MW photo voltaic power plant located on Rough & Ready Island with a commercial operation date of December 31, 2011. It was the Port's intent to consider entering into a Power Purchase Agreement for a portion of the output necessary to meet its RPS requirements. The Port proceeded with the work necessary to first obtain a System Impact Study from PG&E which was accomplished on April 20, 2011. Just prior to that date the Port was advised that it would also have to have the California Independent System Operator (CAISO) perform a Cluster Study to understand the project impact on the CAISO Controlled Grid. PG&E was the party that would interface on behalf of the Port with the CAISO on the cluster study. In April we were advised that the CAISO was re-evaluating their handling of the large number of RPS projects and that the March window for inclusion in the 2011 Cluster Study had closed and Rough & Ready Solar would not be included. Subsequently we received an April 15, 2011 memo form Solar Power Partners that the cost of power from the project was estimated to be $140/MWh. In July the Port was also advised that the results of a PG&E 50 MW Solar PPA Solicitation resulted in the winning proposal to be less than $108/MWh. Although Solar Power Partners decided not to go forward with the project, the Port did expend

significant funds on the development of the project. Some of that information is directly applicable to the current West Complex Solar Project. Although the project would have benefited the Port in meeting its RPS requirements the price of power would have been prohibitive for the Port at a time when the California bulk power market was less than $65/MWh including CAISO services.

In summary the Port made a good faith effort to comply with the RPS Standard, however, the economics of the Rough & Ready Solar Project was not favorable to be included in the Port's power supply portfolio.

2012 Activities and Results

During 2012 the Port formalized its Energy Efficiency Plan and had a manual prepared and associated documentation. The manual is based on the "2011 Statewide Customized Offering Procedures Manual for Business" administered by PG&E, SCE, and SDG&E. Previous to the preparation of a manual the Port had a less formal procedure for incentivizing energy efficiency measures. Although more flexible, the informal approach did not have the response intended. The manual was completed and offered to its tenants is late 2012.

The Port also pursued an opportunity for a developer sponsored photovoltaic project proposed by major developer. A 2 MW PV plant was proposed to the Port including a 20 year Power Purchase Agreement starting in 2013 at $105/MWh with an annual 3% escalator on the rate. The turnkey price for the project was approximately $6 million. At the same time, the Port's price of bulk electricity and services under its supply contract at the end of 2012 was slightly less than $63/MWh.

During 2012 the Port completed its plan for compliance with the California RPS Standard. The plan was reviewed with the Port's Rough & Ready Island tenants in a public workshop, took comments and finalized its plan. The plan called for the development of an onsite 1.5 MW photovoltaic generating plant. In the process of developing the plan it was determined that the combination of development and construction of the West Complex Solar Plant and the purchase of Renewable Energy Certificates within the limitations of the Standard would be the best approach to meeting the Renewable Portfolio Standard while minimizing the economic risks associated with committing to a developer sponsored project or the Port's own Rough & Ready Solar Project in 2013.

2012 Schedule Impacts

The initial schedule for the West Complex Solar Project was developed in 2012 with 12 milestones identified and tentative dates for completion. The times estimated for each task reflected moving forward with the PV project as the major objective. (See Table 2) The schedule provided time to adjust project design but did not recognize time required to investigate other alternative RPS compliant projects such as biomass.

Port of Stockton
Compliance Report Form for POUs
2011-13 Narratives

Table 2 - West Complex Solar Plant Schedule					
Task	Time	Scheduled Start Task	Actual Start	Scheduled Complete	Actual Complete
1. Prepare single line and technical sup.	2 Weeks	Nov. 15, 2012	Nov. 15, 2012	Dec. 1, 2012	**Dec. 15, 2012**
2. Notice PG&E and CAISO	1 day	Dec. 2, 2012	Jan. 31, 2012	Dec. 2, 2012	**Jan. 3, 2013**
3. Commence PG&E Studies	6 Months	Dec. 2, 2012	August 9, 2013	May 31, 2013	**Dec. 31,2013***
4. Prepare 2013/14 budget item	3 Months	Dec. 1, 2012	Jan. 1, 2013	March 1, 2013	**May 6, 2013**
5. Obtain 2013/14 budget approval	4 Months	Mar. 1, 2013	Mar. 1, 2013	June 30,2013	**June 30, 2013**
6. Start Arrangements for Financing	7 Months	Mar. 1, 2013		Sept. 30, 2013	
7. Start Bid Documents Preparation	3 Months	July 1, 2013		Sept. 30, 2013	
8. Release Bid and Start RFP process	3 Months	Oct. 1, 2013		Dec. 31, 2013	
9. Award Bid		Jan. 2, 2014			
10. Start Procurement and Construction	10 Months	Jan. 2, 2014		Oct. 31, 2014	
11. Testing	1 Month	Nov. 1, 2014		Nov. 30, 2014	
12. Commercial Operation Date				Dec. 31, 2014	

*Estimated

The project schedule called for award of bids by January 2, 2014 with approximately a 12 month construction time. However, the schedule did not anticipate the time required to investigate additional project considerations with respect to size, use of battery storage and alternatives to the PV plant.

Because the historic proposed cost of developer projects and the Port's West Complex Solar Project have exceeded the current market cost of electricity the Port has taken a cautious approach to committing to a project. Power plant prices have been moving closer to bulk power market prices and the Port has continued to develop its own project. Our purchase of RECs for 2012 reflects the 25% limitation of the 20% of retail sales renewable requirement.

2013 Activities and Results

During the first half of 2013 the Port continued its development of the West Complex Solar Project. By July PG&E and the Port staff had agreed on a course of study of the possible impacts by the PV plant to local transmission system. The Port entered into a System Impact Study Plan with PG&E in July and have reviewed the results of that plan. At the same time it decided to consider increasing the size of the plan to 2 MW.

In addition to the West Complex Solar Plant development the Port is continuing its review of other developer proposed projects. The most recent is a biomass plant proposed by a potential tenant for Rough & Ready Island. Details of this plant have not been provided.

The Port's cost of bulk electricity and services under its supply contract for 2013 was slightly over $75/MWh.

In early 2014 the Port, as part of its due diligence for the PV project surveyed the market to determine the cost of other alternatives to the PV project. In March it determined that there were significant savings to be obtained through the use of Category 1 Renewable Energy Certificates (RECs) in

conjunction with the limited Category 3 RECs. At this time the Port has suspended the development of the West Complex Photovoltaic Project in favor of the purchase of RECs. It has obtained an offer from the Port's current power supplier to provide Category 1 and 3 RECs to meet its RPS requirements though 2017. The Category 1 and 3 RECs are tied to existing, certified power plants consistent with Public Utilities Code Section 399.16 (b)(1)(A) and 399.16 (b)(3). The Confirmations for these purchases will be completed in July or early August 2014.

This year is the first full year for the implementation of the Port's formal Energy Efficiency Program. In FY2012/13 and in FY2013/14 the Port allocated $75,000 for potential rebates under the Energy Efficiency Program. During 2013 there have been a limited number of inquiries and in January 2014 a large customer submitted an application for a lighting retrofit project that would result in a savings of over 55,000 kWhs. That project is currently in the installation process and the Port is waiting on completion. For the coming year the Port has indicated that a review of potential barriers involving paper work complexity and flow. These areas will be reviewed with the objective of stimulating additional participation.

2013 Schedule Impacts

During the first half of 2013 the Port was approached by a biomass developer that was interested in constructing a large biomass plant and selling some of the power to the Port. Because the project proponent would construct the plant and sell power to the Port under a Power Purchase Agreement the Port would not have to fund the initial capital construction cost and therefore would provide an advantage. This proposal will be under consideration by the Port as an alternative or fall back to the West Complex Solar Project.

The time to refine the scope of PG&E System Impact Study was not provided for in the initial schedule. Additional time was necessary to adequately define the parameters and arrive at a scope of study that would be satisfactory to the Port and PG&E. The study was completed in January 2014. There were no significant or limiting impacts from the proposed 2 MW West Complex PV Project to the 60 kV system. The PV project is currently suspended in favor of the purchase of RECs from certified generation through 2017.

Cost Limitation Completeness Check List

POU: Port of Stockton

Date: August 15, 2016

Response to CEC Questions dated July 15, 2016

Section 3207 (d)(6) requires the POUs to provide:

1. Documentation to justify the application of any optional compliance measures adopted by the POU in accordance with section 3206.

   The Port has compiled two documents in response to this question:

   A. A supplemental narrative that briefly summarizes the documents representing the information the Port used to try and develop local renewable resources in order to meet its RPS goals for the 2011-2013 Compliance Period. The documentation provides the detailed background of several project development efforts and external delays that were encountered along the way. **(See 160815_Port of Stockton – Compliance Period 1 Supplemental Narrative)**

   B. A timeline spreadsheet that correlates with the supplemental narrative. The spreadsheet is intended to show the timing of the steps that the Port undertook in order to meet its RPS goals (**See spreadsheet – 160815_CP1 Port of Stockton Timeline (2011-2013).xlsx)**

2. All reports, analyses, proposed findings, and any other information upon which the POU relied in applying the measures.

   The same supplemental narrative provided in response to Question 1 provides the information requested. **(See 160815_Port of Stockton – Compliance Period 1 Supplemental Narrative and the 160815_CP1 Port of Stockton Timeline (2011-2013).xlsx)**

Section 3207 (d)(6)(A) requires:

3. The cost limitation reported in dollars spent during the compliance period

   The Port compiled a summary spreadsheet with supporting details of its expenditures for RPS compliance during the Compliance Period 1 (CP1). The spreadsheet also provides an estimation of the potential Port expenses for the purchase of RECs during

the same compliance period. However, the cost estimate is based upon the key assumption that RECs were possibly available for purchase during the CP1 period at a cost equal to the Port's REC market price for CP2. Although there were significant funds expended during CP1, there was additional staff time that was not included in the analysis. **(See spreadsheet – 160815_Solar Project Expenses 2010-2014 for Port of Stockton.xlsx)**

4. An estimate of the total cost to procure sufficient electricity products to meet the RPS procurement requirements for the preceding compliance period

   As noted in the prior response the same spreadsheet provides a cost estimate for the purchase of sufficient RECs to meet the Port's CP1 targets. **(See spreadsheet – 160815_Solar Project Expenses 2010-2014 for Port of Stockton.xlsx)**

5. Actions taken in response to RPS procurement expenditures meeting or exceeding the cost limitation

   As noted in the supplemental narrative, throughout CP1, the Port continued to pursue the development of local renewable projects. Even though the Port's local renewable projects met with several external delays, the Port continued seek the necessary permits, complete the necessary system impact studies with PG&E (and the CAISO) and follow through on the necessary environmental studies. At the same time the Port continued to review alternative renewable projects that were presented by developers.

   In 2014, after the successful completion of the PG&E system impact study for the installation of a 1.5MW solar project at the Port, the cost of completing the local renewable project exceeded the option to purchase RECs from the California market. At that time the Port chose to suspend the development of the local solar project and purchase sufficient going forward RECs from the California market.

   The timeline spreadsheet provides a summary of the actions taken by the Port during CP1. **(See spreadsheet – 160815_CP1 Port of Stockton Timeline (2011-2013).xlsx)**

Section 3206 (a)(3)(B) requires:

Supporting documentation demonstrating that the adopted cost limitations ensure that:

6. The limitation is set at a level that prevents disproportionate rate impacts

   The Port's consultant provided the Port with several project cost estimates and rate impact studies regarding the Port's on-going RPS plans when compared to the local investor owned utility. **Please see the following documents:**

   100503_April 26 SSI Proposal Comments.docx

   2014-01-13 RPS_Procurement_Plan.pdf

   100503_April 26 SSI Proposal Comments.docx

   120426_Lorraine Gonzalez Comments on Pre-Rule Making Regs.pdf

   140505_PV Plant-REC Recommendation.pdf)

7. The costs of all procurement credited toward achieving the RPS are counted toward the limitation

   The Port compiled a summary spreadsheet with supporting details of its expenditures for RPS compliance during CP1. The spreadsheet also provides an estimation of the potential Port expenses for the purchase of RECs during the same compliance period. However, the cost estimate is based upon the key assumption that RECs were possibly available for purchase during the CP1 period at a cost equal to the Port's REC market price for CP2. **(See spreadsheet – 160815_Solar Project Expenses 2010-2014 for Port of Stockton.xlsx)**

8. The procurement expenditures do not include any indirect expenses

   The Port has included the following direct costs:

   Consulting studies
   Engineering
   PG&E System Impact Studies
   REC purchase
   WREGIS participation
   20% for Port staff payroll tax

(See spreadsheet – 160815_Port of Stockton Solar Project Expenses 2010-2014.xlsx)

Section 3206 (a)(3)(C) requires:

Supporting documentation demonstrating that the POU's adopted cost limitation rules takes into account the following:

9. The POU's most recent procurement plan

   On August 11, 2016, the Port held a public meeting to discuss the Port's efforts during CP1 and its current procurement plan for CP2 and CP3 **(See Document – 160811_Board RPS Procurement Plan 2016 Update)**

10. The procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable resources

    Over the years the Port received numerous estimates of the cost of the local renewable projects it was attempting to develop. Following is a list of several of the documents that contain project cost estimates. **Please see the following documents:**

    100503_April 26 SSI Proposal Comments.docx
    1500KW Solar PV Electrical System Installation 10-29-12 W-CK Comments.doc
    130214_PV Gen Funding Memo.pdf
    Government PGE Projects 2013 to Present (2).pdf
    Estimated Cost of Renewable and Fossil Generation in CA CEC-200-2014-003.pdf
    140131_PV Project Construction Options.pdf)
    140505_PV Plant-REC Recommendation.pdf)

11. The potential that some resource additions would be canceled or delayed

    The Port of Stockton operates as an interconnected electric utility with PG&E. The interconnection agreement with PG&E contains the requirement for the Port to notify PG&E of any "Significant Impacts" between the utilities that may need to be studied in order to see what system improvements, if any, may be necessary. Such studies can be time consuming and potentially uncover system changes that could either be cost prohibitive or present significant implementation delays to a proposed project. The Port experienced these external delays for both local projects it attempted to complete. **Please see the following documents:**

    101022_Letter to Zahner on Connecting RRS.pdf

101206_Notice to PG&E.pdf
101220_RPS Small Gen Application.pdf
110207_SPP Rough Ready Solar_Stockton Port District_SIS Study Plan_FINAL.doc
110329_PG&E Identifies Deliverability Issue.pdf
110331_CAISO Identifies Deliverability Issues.pdf
110421_March 31 Minutes FINAL.doc
110415_RPS Memo to POS 041511.docx
110615_RIS POS Generator Interconnection Application 061511.doc
110623_Cluster Study Delay by CAISO.pdf
110724_Roberts Island Solar and Price of PV.pdf
110801_RRS Put on Hold by PG&E.pdf
130103_Significant Operational Change Notice.pdf
130214_PV Gen Funding Memo.pdf
130809_System Impact Study_Signed.pdf
Port of Stockton_Rough & Ready Solar SIS Report_DRAFT – 2013.10.22.doc
Port of Stockton_Rough & Ready Solar SIS Report – 2014.01.15.doc, Appendix A – Study Plan.pdf, Appendix B – Contingency Lists.pdf, Appendix C – Power Flow Plots.pdf, Appendix D – Preliminary Protection Requirements R1.pdf
140505_PV Plant_REC Letter (2).pdf

Section 3206 (a)(3)(D)-(E) requires:

Supporting documentation demonstrating that the applied cost limitation includes:

12. Only those types of procurement expenditures that are permitted under the adopted cost limitation rule

The Port has included the following direct costs:

Consulting studies
Engineering
PG&E System Impact Studies
REC purchase
WREGIS participation
20% for Port staff payroll tax.

(See spreadsheet – 160815_Solar Project Expenses 2010-2014 for Port of Stockton.xlsx)

13. The planned actions to be taken in the event projected cost of meeting the RPS requirements exceeds cost limitation

The Port did not set a yearly RPS cost limitation. Throughout the CP1, the Port diligently continued its efforts to develop a local renewable project. Even though the Port's efforts met with external delays, the Port continued to expend the necessary funds to move the projects forward and review alternatives. Only during a final due diligence review just prior to ordering solar equipment for the 1.5MW solar project, the consultant's review showed that the completion of the local renewable project would be more expensive than purchasing RECs from the California market. **(See Document – 2014-01-13 RPS_Procurement_Plan.pdf)**

Chronology of Port of Stockton RPS Decisions for CP1

Doc Count		Year	Month	Doc Date	Document Description
		2010	January		
		2010	Feburary		
		2010	March		
		2010	April		
1		2010	May	5/3/2010	Consultant memo on 20MW Solar Project proposal comparisons
2		2010	June	6/29/2010	Stockton Energy Center licence agreement with Port to build solar rooftop project
		2010	July		
		2010	August		
		2010	September		
3		2010	October	10/22/2010	Initial Port repsonse to RR&S to development of 20MW solar rooftop project
4		2010	November	11/22/2010	Port System Imapct Study plan for Rough& Ready rooftop solar project
5		2010	December	12/6/2010	Port sends 20MW project notification to PG&E pursuant to interconnection agreement terms
6				12/20/2010	Port sends small generator application to PG&E
	CP 1	2011	January		
7	CP 1	2011	Feburary	2/4/2011	PG&E issues initial System Impact Report for 17 MW project to be commercial by December 31, 2011
8	CP 1			2/18/2011	Port issues PG&E a $25,00 check to start the necessary studies to build the Rough & Ready Solar Project
9	CP 1	2011	March	3/29/2011	PG&E email explains deliverability issues related to CAISO Tariff
10				3/31/2011	Email from CAISO explains that CAISO Tariff does not allow for Project inclusion in cluster study till the Tariff is changed
11				3/31/2011	Port Board memo on issues with CAISO and PG&E "fitting in" a 20MW solar project
12	CP 1	2011	April	4/15/2011	Rough & Ready Solar Developer concludes that the solar project will not be commercially viable in CAISO market
13	CP 1			4/20/2011	System Imapcts Study report release on 20 MW solar rooftop project
	CP 1	2011	May		
14	CP 1	2011	June	6/15/2011	The Port completed a Generator Interconnection request for the Next Energy Concepts proposal for a 25MW solar interconnect to the Port's 25MVA substation
15	CP 1	2011	July	7/24/2011	email noting rezoning issues that will need to be addressed for project and solar pricing from PG&E
16	CP 1	2011	August	8/1/2011	**email from PG&E puts Port solar project on hold due to CAISO Cluster study**
	CP 1	2011	September		
	CP 1	2011	October		
17	CP 1	2011	November	11/4/2011	email on CAISO Cluster study deliverability issues that will impact the Port's solar project
	CP 1	2011	December		
	CP 1				
18	CP 1	2012	January	1/10/2012	Memo from energy consultant recommending that the Port pursue the development of a 1.5MW PG generating station and supplemental purchase of RECs from the market
	CP 1	2012	Feburary		
19	CP 1	2012	March	3/30/2012	Proposal from Next Energy Concepts, LLC, for a 1MW solar array located on warehouse rooftops.
20	CP 1	2012	April	4/19/2012	Memo from energy consultant discussing cost limitations and recommending that the Port develop a compliance plan for the 33%
21				4/27/2012	**Letter from Port to CEC on small utility meeting RPS**
22	CP 1	2012	May	5/31/2012	HCS proposal for design/engineering of a 500kW solar project at the Port
	CP 1				
	CP 1	2012	June		
23	CP 1	2012	July	7/17/2012	Attachment B - Port of Stockton Cost impact comments to the CEC
	CP 1	2012	August		
	CP 1	2012	September		
	CP 1	2012	October		
24	CP 1	2012	November	11/7/2012	Engineering and design proposal from HCS Engineering for 1.5MW ground based solar project at the Port
25	CP 1			11/20/2012	Report to Board of Change in Plan for Port to develop a local 1.5 to 2 MW solar project to meet RPS, includes rate implications for RPS alternatives
26	CP 1			11/29/2012	Engineering and design proposal from HCS Engineering for 1.5MW ground based solar project at the Port
7	CP 1	2012	December	12/18/2012	Power point presentation for the Port's public meeting on RPS Plan
28				12/20/2012	Port held a public meeting on RPS plan
29	CP 1			12/21/2012	Port confirm with Shell for 607 RECs for 2013
30	CP 1			12/21/2012	Port confirm with Shell for 388 RECs for 2014
	CP 1				
31	CP 1	2013	January	1/3/2013	Letter sent to PG&E notification of 1.5MW solar plant at Port
32	CP 1			1/4/2013	Letter sent to CEC as notice of new RPS plan
33	CP 1	2013	Feburary	2/12/2013	Electrical Interconnection proposal for 1.5MW solar system from HCS Engineering of Stockton
34	CP 1			2/13/2013	Memo from energy consultant recommending that the Port proceed with the 1.5MW solar project and use public purpose funding for the PG&E system impact study
35	CP 1	2013	March	3/6/2013	Port consultant recommend the Port join WREGIS
36	CP 1			3/7/2013	Port joins WREGIS
	CP 1	2013	April		
	CP 1	2013	May		
	CP 1	2013	June		
37	CP 1	2013	July	7/17/2013	Port requests PG&E to study addition of 2MW Project on Port property
38	CP 1			7/17/2013	PG&E initiates System Impact Study for 2MW project at Port
39	CP 1	2013	August	8/1/2013	[redacted]
40	CP 1			8/29/2012	Port receives a power purchase proposal for a 2MW solar project at $0.110
	CP 1	2013	September		
41	CP 1	2013	October	10/22/2013	PG&E releases a draft System Impact Study Report for 1.5-2MW Solar Projedt at Port
42	CP 1	2013	November	11/21/2013	Port files ammended RPS POU Narative Reports with CEC documenting 2011-2013 RPS efforts
	CP 1	2013	December		
43	CP 2	2014	January	1/15/2014	PG&E release System Impact Study Report for 1.5 - 2.0 MW Solar Project at Port of Stockton
44	CP 2			1/31/2014	Consultant report on options to proceed with Port's solar paint
	CP 2	2014	Feburary	2/6/2014	RGS Energy Proposal to Port for 1.2MW fixed solar project at Port site - marked CONFIDENTIAL
45	CP 2			2/7/2014	California Solar Statistics document cost of solar systems by size
	CP 2	2014	March		
	CP 2	2014	April		
46	CP 2	2014	May	5/1/2014	CEC Report on the Cost of new Renewable and Fossil generation in California
47	CP 2			5/5/2014	**Memo from Cornerstone recommending drop the 2MW solar porject an purchase PCC1 RECs from Shell thru 2017**
48	CP 2			5/5/2014	**Port sent memo to RGS turning down the 1.2MW project and noted that the Port would be buying RECs from the California** market
49	CP 2	2014	June	6/30/2014	Port files RPS Plan narrative for 2011-2013 with CEC
50	CP 2	2014	July	7/1/2014	Port files RPS POU Narative Reports with CEC documenting 2011-2013 RPS efforts
51	CP 2			7/29/2014	Port files WREGIS attestation with CEC
	CP 2	2014	August		
52	CP 2	2014	September	9/18/2014	CEC RPS forms for 607 REC purchase notice
53	CP 2			9/26/2014	Finalize REC purchases from Shell for 2014-2017
54	CP 2	2014	October	10/27/2014	Amended RPS filing with the CEC noting the 607 RECs
	CP 2	2014	November		
	CP 2	2014	December		

Port of Stockton
Renewable Portfolio Standard Compliance Period 1 Supplemental Narrative

During RPS Compliance Period 1 (2011-2013), the Port of Stockton (Port) proceeded diligently to develop local renewable energy projects that would provide the Port with sufficient state certifiable renewable energy to meet the Port's RPS goals.

While attempting to develop the local renewable projects, the Port undertook reasonable measures under its control and consistent with its obligations under local, state and federal laws and regulations to develop and construct the necessary facilities needed to generate and transmit the renewable electricity to the Port's 3 MW retail retail electric load. However, the local projects experienced numerous study delays beyond the control of the Port that ultimately led to the cancellation of the construction of a local solar project and the Port's decision to purchase the necessary Renewable Energy Credits (RECs) from the California market. During the same time period, the Port continued to review alternative renewable projects

The following narrative provides a brief chronological summary and support documentation of the actions taken by the Port demonstrating reasonable progress toward meeting its 2011-2013 RPS procurement goal.

2010

On May 3, 2010 the Port's energy consultant provided a brief review of a new Stockton Energy Center LLC (SEC) proposal for the construction of a 20MW solar rooftop system at an estimated price of $3.75/watt. The recommendation was to further explore the offer from SEC. **(Document – 100503_April 26 SSI Proposal Comments.docx)**

On June 29, 2010 Stockton Energy Center LLC (SEC) entered into a License Agreement with the Stockton Port District in which SEC would have access to the roofs of 37 warehouses on Rough & Ready Island for the purpose of installing of 20MW of individual solar generation systems on each of the roofs. **(Document – 101122_Executed SIFS Agreement w RRS 11-22-10.pdf)**

On October 22, 2010 the Port discussed the 20MW Rough & Ready Solar Project's interconnection with the Port facilities and service to the CAISO grid through PG&E's transmission system. Further, the interconnection process would require a System Impact and Facility Study to be performed by PG&E. **(Document – 101022_Letter to Zahner on Connecting RRS.pdf)**

On December 6, 2010, pursuant to the terms if their interconnection agreement with PG&E, the Port notified PG&E of the potential interconnection of a 20MW solar project that may create a "significant operational change". The project startup was anticipated to be late 2011. **(Document – 101206_Notice to PG&E.pdf)**

On December 20, 2010, the Port sent a completed small generator application form to PG&E for the Rough & Ready solar generation project requesting a net metering option. **(Document – 101220_RPS Small Gen Application.pdf)**

Port of Stockton
Renewable Portfolio Standard Compliance Period 1 Supplemental Narrative

2011

On February 4, 2011 PG&E issued an initial System Impact Study Plan for the Rough & Ready solar project. The SIS schedule called for PG&E to receive payment of study fees by mid February, 2011 and have a final report by +30 business days **(Document – 110207_SPP Rough Ready Solar_Stockton Port District_SIS Study Plan_FINAL.doc)**

On February 18, 2011 the Port sent PG&E a check for $25,000 to begin the System Impact Study Plan for the Rough & Ready solar project. The SIS schedule called for PG&E to receive payment of study fees by mid February, 2011 and have a final report by +30 business days **(Document – 110217_SIS Signed.pdf)**

On March 29, 2011 in an email PG&E tried to explain to the Port that the CAISO Tariff did not allow for the inclusion of the Port's proposed joint solar project because the project would not be direct connected to the CAISO grid and the Tariff did not address indirectly connected projects. Thus, the proposed solar project would receive a lower payment for any energy produced. **(Document – 110329_PG&E Identifies Deliverability Issue.pdf)**

On March 31, 2011 in an email CAISO explains that the Tariff does not allow for the Port's proposed project to be included in the Cluster study until the CAISO tariff gets modified to incorporate non-participating transmission owners, like the Port. **(Document – 110331_CAISO Identifies Deliverability Issues.pdf)**

On March 31, 2011 the Port staff met to hear about transmission cluster study and CAISO tariff issues. The project connected to the Port and then interconnected through the Port to PG&E does not fit in the CAISO tariff without changes that cannot be counted on to occur. The solar project is at risk for not being incorporated in the upcoming cluster study and may not be useable by PG&E. **(Document – 110421_March 31 Minutes FINAL.doc)**

On April 15, 2011 the project developer for the 20MW Rough & Ready Solar Project sent the Port a letter stating that the solar rooftop project has not been successful in getting a Power Purchase Agreement with PG&E for the bulk of the output energy from the project. Therefore, would the Port entertain a 10-15MW ground based alternative. The Port's entire retail load was about 3MW at that time. **(Document – 110415_RPS Memo to POS 041511.docx)**

On June 15, 2011 the Port completed a generation interconnection request for the developer Next Energy Concepts, LLC, a successor to Rough & Ready Solar. The proposed solar project was for a 25MW ground based system that would interconnect to the Port's 25MWV substation or Western's 230kV transmission system to be commercial by November 2013. **(Document – 110615_RIS POS Generator Interconnection Application 061511.doc)**

On June 23, 2011 email from Next Energy Concepts that notes all of the steps that the Rough & Ready Solar project have completed only to find that they need a Deliverability Assessment before they can participate in CAISO cluster study. **(Document – 110623_Cluster Study Delay by CAISO.pdf)**

On July 24, 2011 email from Zahner discusses rezoning issues that will need to be addressed for the Port's Roberts Island parcels. The note further discusses the price of PG&E solar projects in the $108/MWHr range. **(Document – 110724_Roberts Island Solar and Price of PV.pdf)**

On August 1, 2011 email from PG&E noted that the Port's solar project had been put on HOLD while PG&E worked on CAISO Cluster study not including the Port's project. **(Document – 110801_RRS Put on Hold by PG&E.pdf)**

On November 4, 2011 the Port and Zahner received a report from the CAISO regarding Cluster study deliverability concerns for generator interconnections. **(Document – 111104_CAISO Deliverability Issues and Timing.pdf)**

2012

On January 10, 2012, the Port received a memo from its energy consultant recommending that the Port expend funds to construct a 1.5MW PV generation station at the Port in conjunction with the purchase of a limited amount of RECs from the market with the emphasis on local construction of a renewable resource. The combination of construction expense and purchase of REC were undertaken as an approach to meeting the RPS requirements. The estimated commercial operations date of a local project was Dec. 31, 2014 **(Document – 121109_PV Generation Station Preliminary Schedule.pdf)**

On March 30, 2012, the Port received a design/construct proposal from Next Energy Concepts for the development of a 1MW solar rooftop system located on Port facilities, owned by the Port. No costs or timelines were proposed in the letter. **(Document – 120330_WCS Proposal 03212.docx)**

On April 19, 2012, the Port received a memo from its energy consultant discussing RPS cost limitations and recommending that the Port develop a compliance plan for the 33% **(Document – 120419_Summary of CEC Webinar on propose RPS Regs.docx)**

On April 27, 2012, the Port sent a letter to the CEC discussion the impacts RPS compliance can have on micro-utilities, like the Port. The letter provides a summary of the Port's RPS development efforts and recommends that the CEC allow small POUs to be able to rely fully on the REC market to meet its RPS targets up to the 33% **(Document – 120426_Lorraine Gonzalez Comments on Pre0Rule Making Regs.pdf)**

Port of Stockton
Renewable Portfolio Standard Compliance Period 1 Supplemental Narrative

On May 31, 2012, the Port received a design/construct proposal from HCS Engineering of Stockton for the development of a 500kW solar rooftop system located on Port facilities, owned by the Port. No costs or timelines were proposed in the letter. **(Document – 500KW Solar PV Electrical System Installation 5-31-12 DRAFT.doc)**

On July 17, 2012, the Port provided cost impact comments to the CEC regarding the implementation costs associated with the RPS regulations. Emphasis was made on the upward pressure on rates of upward of 8.25% on the revenue requirement due to the higher costs of developing renewable resources. **(Document – 120717_Attachment B – Port of Stockton Cost Impact Comments.xlsx)**

On August 29, 2012, the Port received a Power Purchase proposal for the output from a 2MW solar system at a rate of $0.110 /kWh from MAGNAN renewables. **(Document – 120829_Mangan Est of PV Project Cost.pdf)**

On November 7, 2012, the Port received an engineer/design/construct proposal form HCS Engineering of Stockton for the design of a 1.5MW ground based solar project located at the Port. The estimated cost of the proposed project was about $1.65 million. **(Document – 1500KW Solar PV Electrical System Installation 10-29-12 W-CK Comments.doc)**

On November 20, 2012, the Port issued its revised RPS Procurement Plan. The Plan included narrative about the Port's prior solar project development effort, cost analysis for a new 1.5-2MW local ground based solar project, retail rate implications and a project timeline. **(See Document – 2014-01-13_RPS Procurement Plan.pdf)**

On November 29, 2012, the Port received another engineer/design/construct proposal form HCS Engineering of Stockton for the design of a 1.5MW ground based solar project located at the Port. The estimated cost of the proposed project was about $1.65 million. **(Document – 1500KW Solar PV Electrical System Installation 10-29-12 W-CK Comments.doc)**

On December 20, 2012, the Port held a public meeting to discuss its revised RPS plan. The attached file is the power point presentation for the meeting. **(Document – 121218_RPS Procurement Plan.ppt)**

On December 20, 2012, the Port held a public meeting to discuss its revised draft RPS plan for the development of a 1.5MW local solar project. The Port received minimal public comments on the plan. **(Document – 2012-12-20 Notice_of_public_meeting_RPS_Procurement.pdf)**

On December 21, 2012, the Port entered into two Confirmation Agreements with Shell to purchase 607 Vintage year 2013 PCC3 RECs and 387 Vintage year 2014 PCC3 RECs. The purchased RECs were to complement the output of the 1.5-2MW local solar project that was still under SIS review by PG&E. **(Document – REC Confirmation Agmt CY 2013 20121221131546685.pdf, REC Confirmation Agmt CY 2014 20121221131215865.pdf)**

Port of Stockton
Renewable Portfolio Standard Compliance Period 1 Supplemental Narrative

2013

On January 3, 2013, pursuant to the terms if their interconnection agreement with PG&E, the Port notified PG&E of the potential interconnection of a new 1.5MW solar project that may create a "significant operational change". **(Document – 130103_Significant Operational Change Notice.pdf)**

On January 4, 2013, the Port sent a notice to the CEC advising them of the public meeting and updated RPS Procurement Plan. **(Document – 130104_RPS Procurement Plan Advise.pdf)**

On February 12, 2013, the Port received a proposal from HCS Engineering of Stockton the for design and construction of the electrical interconnection for a 1.5MW solar project at Port facilities. **(Document – 130212_pv proposal 1-16-13.docx)**

On February 13, 2013, the Port's energy consultant recommended that the Port proceed with the PG&E system impact study for a 1.5MW solar project located on Port property using public purpose funding to pay for the study costs. The project was estimated to cost $1.8 million with commercial operation by early 2015. **(Document – 130214_PV Gen Funding Memo.pdf)**

On March 6, 2013, the Port's consultant submitted a memo recommending that the Port register with WREGIS so that the Port can properly retire the PCC3 RECs purchased for Vintage year 2013 and 2014. **(Document – 130306_WREGIS Registration.pdf)**

On March 7, 2013, the Port signed the WREGIS Account Holder Registration Agreement. **(Document – WREGIS Registration APP.pdf)**

On July 17, 2013, PG&E issued an initial System Impact Study Plan for the new 2MW Rough & Ready Island Solar Project. The new SIS schedule called for PG&E to receive payment of study fees by late July, 2013 with a final report by October, 2013. PG&E issued the final report on January 15, 2014. **(Document – 130809_System Impact Study_Signed.pdf)**

On October 22, 2013, PG&E issued a draft System Impact Study Plan for the new 2MW Rough & Ready Island Solar Project. **(Document – Port of Stockton_Rough & Ready Solar SIS Report_DRAFT – 2013.10.22.doc)**

In August, 2013, the CEC adopted Enforcement Procedures for the RPS for Local Publically Owned Electric Utilities. CEC-300-2013-002-CFM provided the detailed regulations for POUs to follow relative to RPS compliance reporting. **(Document – 130801_RPS Adopted RegsCEC-300-2013-002-CFM.pdf)**

Port of Stockton
Renewable Portfolio Standard Compliance Period 1 Supplemental Narrative

2014

On January 15, 2014, PG&E issued its final System Impact Study Plan for the new 2MW Rough & Ready Island Solar Project. The new SIS report concluded the project would not have significant impacts if it was operated as a NON-export interconnection with PG&E. **(Document – Port of Stockton_Rough & Ready Solar SIS Report – 2014.01.15.doc, Appendix A – Study Plan.pdf, Appendix B – Contingency Lists.pdf, Appendix C – Power Flow Plots.pdf, Appendix D – Preliminary Protection Requirements R1.pdf)**

On January 31, 2014, the Port's consultant issued a memo to the Port on the various options for proceeding with the construction of the ground based 1.5-2MW solar project. **(Document – 140131_PV Project Construction Options.pdf)**

On February 6, 2014, the Port received a proposal from RGS Energy for the development of a 1.2MW ground based solar project to be located on Port facilities. The Report is marked CONFIDENTIAL. **(Document – 140207_PORT PROPOSAL FINAL TO EMAIL.pdf-Not Included)**

On February 7, 2014, the California Solar Statistics report provided documentation of the Cost of Solar systems by size. The information was useful for the Port to evaluate the solar proposals it was receiving. **(Document – Government PGE Projects 2013 to Present (2).pdf)**

In May 2014, the CEC issued a report on the "Estimated Cost of New Renewable and Fossil Generation in California (CEC-200-2014-003-SD). The report provided insight into the importance of tax incentives for the development of renewable project. The Port is a tax-exempt entity and thus the renewable project financials are significantly different than for a taxable entity that can take full advantage of the tax incentives. **(Document – Estimated Cost of Renewable and Fossil Generation in CA CEC-200-2014-003.pdf)**

On May 5, 2014, the Port received a due diligence memo from its consultant discussing the going forward development costs of a 1.5MW local solar project compared to purchasing the RECs from the California market. The recommendation was to drop the project and purchase RECs from the market. **(Document – 2014-01-13 RPS_Procurement_Plan.pdf)**

On May 5, 2014, the Port sent a letter to RGS Energy notifying them that the Port would not be pursuing their 1.2MW solar project. Instead the Port had decided to purchase RECs from the California market. **(Document – 140505_PV Plant_REC Letter (2).pdf)**

On June 30, 2014, the Port filed its annual RPS POU report and narratives with the CEC. The report showed the Port's plan to purchase 607 RECs to supplement the small solar project. **(Document – 140630_CEC-RPS-POU.xlsx, 140630_RPS POU Narratives.docx)**

On July 29, 2014, the Port filed its WREGIS attestation form for 2013. **(Document – 140729_Signed Attestation_WREGIS_POU RPS.pdf)**

Port of Stockton
Renewable Portfolio Standard Compliance Period 1 Supplemental Narrative

On September 9, 2014, the Port submitted an amended RPS POU filing clarifying what project the PCC3 RECs came from. **(Document – 140918_STOCK WREGIS RECs PCC3 2014-07-03_CORR.xlsx)**

On September 9, 2014, the Port submitted an amended RPS POU filing clarifying what project the PCC3 RECs came from. **(Document – 140918_STOCK WREGIS RECs PCC3 2014-07-03_CORR.xlsx)**

On September 26, 2014, the Port complete the purchase of PCC1 and PCC3 RECs for Vintage Years 2014-2017. **(Document – Final(9-23-14)_Stockton PCC1.pdf, (9-23-14)_Stockton PCC3.pdf)**

On October 27, 2014, the Port submitted an amended RPS POU filing to the CEC. **(Document – 141027_CEC-RPS-POU Update.xlsx)**

Compliance Period 1 Expense Summary

$	31,591.78	FY10-13 RPS/Solar Expenses Summary
$	32,338.91	FY13-14 RPS/Solar Expenses Summary
$	9,387.82	FY14-15 RPS/Solar Expenses Summary
$	73,318.50	**Subtotal**
$	1,062.25	RECs purchased for 2013
$	1,531.07	WREGIS registration
$	**75,911.82**	**Total Expended by the Port**
$	**107,010.21**	Estimate of 2011-2013 Alternative Purchase of RECs
$	**(31,098.39)**	Difference

Estimation of the Alternative Cost to purchase RECs for 2011-2013 Period if RECs would have been available in California Market

	2011	2012	2013
RPS Percent	20%	20%	20%
PCC3 REC percent	25%	25%	25%
Retail Load (MWH)	9,725.13	12,581.23	14,484.27
Total REC	1,945	2,516	2,897
PCC1 RECs	1,459	1,887	2,173
PCC3 RECs	486	629	724
Purchased PCC3 RECs	-	-	607
Bal of PCC3 RECs	486	629	117
PCC1 REC Cost *	$ 19.00	$ 19.00	$ 19.00
PCC1 REC Cost *	$ 1.75	$ 1.75	$ 1.75
PCC1 $	$ 27,716.61	$ 35,856.50	$ 41,280.18
PCC3 $	$ 850.95	$ 1,100.86	$ 205.12
Total REC Optional Cost	$ 28,567.55	$ 36,957.36	$ 41,485.30
Cummulative REC Cost	$ 28,567.55	$ 65,524.91	**$ 107,010.21**

* - The estimated REC prices shown are based upon the actual REC purchases that the Port comeleted in 2014

Public Purpose Fund Allocation		FY 2010/2011	FY 2011/2012	FY 2012/2013	Grand Totals	RPS/Solar
1	**Rough & Ready Island Solar**					
a.	Cornerstone Consulting	$ 13,749.33	$ 5,586.14	$ 126.00		
b.	HCS Engineering	$ 10,483.75	$ 1,050.00	$ -		
c.	PG&E System Impact Study (SIS)	$ 25,000.00	$ -	$ -		
	R&R Solar Totals	**$ 49,233.08**	**$ 6,636.14**	**$ 126.00**	**$ 55,995.22**	$ 55,995.22
2	**Energy Conservation**					
a.	Cornerstone Consulting	$ -	$ 11,977.04	$ 1,995.00		
	Energy Conservation Totals	**$ -**	**$ 11,977.04**	**$ 1,995.00**	**$ 13,972.04**	
3	**Photovoltaic (PV) Project**					
a.	Cornerstone Consulting	$ -	$ -	$ 1,647.42		
b.	HCS Engineering	$ -	$ -	$ 1,500.00		
c.	PG&E System Impact Study (SIS)	$ -	$ -	$ -		
	PV Project Totals	**$ -**	**$ -**	**$ 3,147.42**	**$ 3,147.42**	$ 3,147.42
4	**RPS Plan Preparation**					
a.	Cornerstone Consulting	$ -	$ 4,158.00	$ 4,692.51		
	RPS Plan Preparation Totals	**$ -**	**$ 4,158.00**	**$ 4,692.51**	**$ 8,850.51**	$ 8,850.51
	Grand Subtotals	**$ 49,233.08**	**$ 22,771.18**	**$ 9,960.93**	**$ 81,965.19**	$ 67,993.15
	Staff Support A&G (20%)	$ 9,846.62	$ 4,554.24	$ 1,992.19	**$ 16,393.04**	$ 13,598.63
	Total Costs	**$ 59,079.70**	**$ 27,325.42**	**$ 11,953.12**	**$ 98,358.23**	$ 81,591.78
	Less Developer Contribution	$ (50,000.00)	$ -	$ -	**$ (50,000.00)**	$ (50,000.00)
Grand Totals		**$ 9,079.70**	**$ 27,325.42**	**$ 11,953.12**	**$ 48,358.23**	$ 31,591.78

Public Purpose Fund Allocation			FY 2013/2014		RPS/Solar	
1	**Energy Conservation**					
	a.	Cornerstone Consulting	$	2,268.00		
	Energy Conservation Totals		**$**	**2,268.00**		
2	**Photovoltaic (PV) Project**					
	a.	Cornerstone Consulting	$	5,205.84		
	b.	HCS Engineering	$	1,596.25		
	c.	PG&E System Impact Study (SIS)	$	20,000.00		
	PV Project Totals		**$**	**26,802.09**	$	26,802.09
3	**RPS Plan Preparation**					
	a.	Cornerstone Consulting	$	147.00		
	RPS Plan Preparation Totals		**$**	**147.00**	$	147.00
	Grand Subtotals		**$**	**29,217.09**	$	26,949.09
		Staff Support A&G (20%)	$	5,843.42	$	5,389.82
Grand Totals			**$**	**35,060.51**	$	32,338.91

Public Purpose Fund Allocation			FY 2014/2015		RPS/Solar
1	**Energy Conservation**				
	a.	Cornerstone Consulting	$1,155.00		
	Energy Conservation Totals		**1,155.00**		
2	**Photovoltaic (PV) Project**				
	a.	Cornerstone Consulting	-		
	b.	HCS Engineering	-		
	c.	Bockmon & Woody	$7,109.18		
	PV Project Totals		**7,109.18**	$	7,109.18
3	**RPS Plan**				
	a.	Cornerstone Consulting	$714.00		
	RPS Plan Preparation Totals		**714.00**		
	Grand Subtotals		**8,978.18**	$	7,823.18
		Staff Support A&G (20%)	1,795.64	$	1,564.64
Grand Totals			**10,773.82**	$	9,387.82

Renewable Portfolio Standard

Procurement Plan 2016 Update

Port of Stockton

August 11, 2016

Port of Stockton
Renewable Portfolio Standard 2016 Procurement Plan Update

I Executive Summary

In order for the Port of Stockton (Port) to meet the California Renewable Portfolio Standard (RPS) procurement goals of 33% of retail sales met by renewable energy[1] by December 31, 2020 and 50% renewable energy[2] by December 31, 2030, the Port has determined that currently the most efficient and cost effective approach is to continue the purchase of sufficient state approved renewable energy products from the active California market.

The Port's retail electric load consists solely of commercial and industrial customers that must compete in a global market with their respective products. In order to help its retail customers succeed, the Port strives to provide cost effective and reliable electric service while complying with the state's aggressive renewable energy standards. In the past, the Port has attempted to develop two local renewable resources only to have both projects fail because of transmission study issues beyond the Port's control.[3]

There are three compliance periods, the first of which is Compliance Period 2011-2013. For this period the Port had determined that it diligently expended significant development funds on a large-scale local renewable project and that after extensive study delays was met with regional development problems beyond the Port's control. Further, a second project, after lengthy study delays beyond the Port's control became too costly when compared to other market alternatives. By the time the project study was completed, the purchase of Renewable Energy Certificates (REC) through an active California market became the most cost effective method to meet the RPS requirements.

For the two Compliance Periods 2014-2020, the Port has purchased sufficient state approved RECs for its existing retail load to meet the state's yearly RPS of 20% in 2014 increasing to 33% by 2020.

For the Compliance Period 2021-2030, the Port will continue to monitor and participate in development of the regulations until the state regulators have completed their efforts to codify the new laws.

II Background

Beginning as early as 2002 California has lead the country in its efforts to reduced greenhouse gasses by the implementation of a series of ground breaking legislative actions. In 2002 CPUC regulated electric utilities were required to meet 20% of their retail electric load with renewable energy by 2017. 2006 legislation accelerated the state's Renewable Portfolio Standard (RPS) to 20% by 2010 for investor owned utilities. Publically owned utilities (POUs) were allowed to set their own RPS goals recognizing the intent of the legislation to attain a statewide goal of 20%. In April 2011

[1] Required by California Senate Bill SX1-2 signed by Governor Brown, April 12, 2011.
[2] Required by California Senate Bill SB350 signed by Governor Brown, October 7, 2015.
[3] Section 3206(2)(A)(1&2)of CEC-300-2013-002-CFM, August 2013

the state implemented an aggressive law (SBX1-2) requiring all electric utilities to achieve a power supply mix of 33% renewable energy from state approved renewable resources by 2020. The law specified a timetable with set compliance periods leading up to the 33 % RPS by 2020. The California Energy Commission (CEC) has been charged with RPS enforcement for POUs like the Port of Stockton. In 2015 Governor Brown signed Senate Bill SB350 to aggressively increase the RPS requirement to 50% by 2030. State regulators are currently working to codify the SB350 requirements into additional regulations for the state's electric utilities.

The Port of Stockton began incorporating renewable resources into its power supply plan in 2010. The Port entered into a development agreement on June 29, 2010 that provided for the purchase of renewable energy from a part of a large-scale solar photovoltaic project. The local project would produce in-state renewable energy from a large 20 MW rooftop photovoltaic power plant located on the Port's south facing warehouse facilities. The developer intended to sell the renewable solar energy to both the Port and PG&E, wherein the Port would purchase sufficient renewable energy from the project to meet its future RPS goals. The large-scale solar project required a System Impact Study (SIS) to be performed by PG&E in coordination with the California Independent System Operator (CAISO). In November 2010, the Port initiated the SIS with PG&E. By May of 2011, after multiple cluster study issues with PG&E and the CAISO and overall project cost issues the developer could not market the bulk of the project output to PG&E and abandoned the large-scale solar project at the Port. Since the proposed solar project's output was over seven times the size of the Port's total retail load, the Port could not step up to purchase the whole project. The Port had to regroup and determine a new course of action to address the state mandated RPS goals.

By mid 2012, the CEC completed draft RPS regulations for POUs. The CEC regulations helped clarify many implementation/definition issues thus helping the California electricity markets develop quantifiable Portfolio Content Categories (PCC) 0 through 4 renewable products that could meet the new regulations. By mid 2012 the Port had completed a design/engineering review of a 1-2MW ground based solar project to be located on Port property. With the design/engineering study completed, the Port developed a new RPS plan for the construction of a 1-2MW solar project on Port facilities supplemented by the purchase of additional vintage 2013 PCC3 RECs from the California market. The Port's RPS plan was reviewed in a public meeting and approved by the Port on December 20, 2012. During the pursuit of the local renewable energy projects, the Port expended about $76,000.

Pursuant to the terms of the Port's interconnection agreement with PG&E, the proposed 1-2MW local solar project required a new SIS be performed by PG&E. The Port requested and paid PG&E to perform the SIS on January 3, 2013. With the construction plans underway, the Port did not commit to purchasing solar panels and support equipment until it had the final SIS results from PG&E. While waiting on the SIS results, the Port computed the additional 2013 RECs it would need in addition to the renewable energy output from the solar project. The Port contracted for the PCC3 REC purchase and joined the Western Renewable Energy Geographic Information System (WREGIS)[3]

[3] The Port joined WREGIS on March 7, 2013.

in order to account for its California certified renewable energy products. The second PG&E SIS took till January 14, 2014 to complete. Upon completion of the PG&E SIS in 2014, the Port's consultant performed a due diligence evaluation on the cost effectiveness of the 1-2MW local solar PV project compared to renewable products available from the developing California renewable energy market. The study showed that market purchased RECs would save an annual 20% compared to the construction/maintenance of a local 1-2MW solar project. After years of trying to construct a local renewable project, during its 2014 budget process the Port determined that it would purchase sufficient state approved RECs for its existing retail load in order to meet the state's yearly RPS target of 20% in 2014.

III Proposed 2016 Procurement Plan Update

For Compliance Period 2011-2013, the Port had determined that it diligently worked to develop a large-scale local renewable project that after extensive study delays by PG&E and the CAISO was met with regional development problems that where beyond the Port's control. Further, after lengthy study delays by PG&E that could not be mitigated, the development of a second local project ultimately became too costly when compared to other market renewable product alternatives

For Compliance Period 2014-2016, the Port has contracted for the purchase of sufficient RECs needed for existing retail load to meet the state's yearly RPS target of 20% in 2014, 20% in 2015 and 25% in 2016.

For Compliance Period 2017-2020, the Port has contracted for the purchase of sufficient RECs needed for existing retail load plus historical growth to meet the state's yearly RPS target of 27% in 2017, 29% in 2018, 31% in 2019 and 33% in 2020.

For the Compliance Period 2021-2030, the Port will wait till the state regulators have completed their efforts to codify the new law after which time the Port will review the most cost effective options at that time.

Therefore, for 2014-2020 period the Port has determined that currently the most efficient and cost effective RPS compliance approach is to continue to purchase sufficient state approved renewable energy products from the active California market. For any additional renewable energy needs for retail load, the Port will continue to review alternative renewable energy projects, on a case-by-case basis, along with market alternatives

Port of Stockton

Supplemental Compliance Report Response to CEC Data Request dated 7/19/2017

2011-2013 CP1

1. ***Additional information needed to determine whether the Port procured an appropriate minimum margin above the level necessary to comply with the RPS to compensate for foreseeable delays or insufficient supply.***
    a. ***Based on the initial schedule for the West Complex Solar Project, the commercial operation date would not occur until the end of 2014. Please identify whether the Port attempted to procure a minimum margin above the level necessary to comply with Compliance Period 1 in order to account for foreseeable delays or insufficient supply.***

The 20 MW solar project was anticipated to be fast tracked and start operation by late 2011. With the anticipated use of RECs from the 20MW solar project, the Port did not initially seek to purchase any additional electric products in 2011-13 to meet CP1. The large solar project would have provided more than enough local PCC1 RECs to meet the Port's compliance needs (see Table 1). However, in

Table 1

Summary of Port's REC Requirements and Availability

	2011	2012	2013	CP1
RPS Percent	20%	20%	20%	20%
PCC3 REC percent	25%	25%	25%	
Port's Retail Load (MWH)	9,725	12,581	14,484	36,791
Total RECs	1,945	2,516	2,897	7,358
PCC1 RECs	1,459	1,887	2,173	
PCC3 RECs	486	629	724	
	2011	**2012**	**2013**	
20MW Solar Project REC Output	155	35,040	35,040	70,235
Port RECs needs	1,945	2,516	2,897	7,358
Balance RECs sold to RPS Market		30,734	32,143	62,877

late 2011, the Port's proposed 20MW solar project fell into an area of a transmission user not addressed in the CAISO tariff. The CAISO would not include the proposed solar project in the

CAISO's transmission cluster study because the project did not fit the parameters of its transmission tariff.

As a result of the inability of the 20MW solar project to be included in the CAISO study and other factors, the Port's large solar project developer ceased development of the project and the Port looked to regroup around a much smaller project.

b. ***What was the quantity of electricity products the Port of Stockton attempted to procure from its various development activities for Compliance Period 1? The Port of Stockton's procurement activities should "demonstrate that the POU would have met its RPS procurement requirements but for the cause of delay" (section 3206 (a)(2)(A)).***

As noted in the response to question 1 above, Table 1 demonstrates that the Port would have met all of its CP1 RPS needs from the large solar project with surplus RECs sold into the market by the developer. When the developer chose to exit the California renewable market, the Port had to revert to an alternative.

On January 10, 2012, the Port began the process of right-sizing the solar project to 1.5-2MW. Throughout 2012, the Port reviewed numerous solar project proposals that included local ownership. On November 20, 2012, the Port issued a revised public RPS Plan that focused on the development of a 1.5-2MW local solar project capable of producing 2,500 MWH of PCC1 RECs to be operational in 2014 and the purchase of supplemental market PCC3 RECs for 2013 and 2014. On December 21, 2012, the Port purchased 607 Vintage 2013 PCC3 RECs.

Energy Commission staff has determined that the following additional information is necessary in order to complete the review of the Port's applied cost limitation for the first compliance period:

1. ***Additional clarification needed for ensuring that the adopted cost limitation rule is set at a level that prevents disproportionate rate impacts. The Port stated: "The Port's consultant provided the Port with several project cost estimates and rate impact studies regarding the Port's on-going RPS plans comparing them to electricity rates of the local investor owned utility."***
    a. ***Is the Port's cost limitation rule designed to keep the Port's rates from exceeding PG&E's rates? If not, what is the Port's cost limitation rule?***

The Port of Stockton's Governing Board has a long-standing policy that the electric rates for Port customers should be less than the comparable rates for PG&E. This is because a primary purpose for the Port operating an electric utility is to serve as an economic driver and attract business to the region. By offering lower rates, the Port can help encourage businesses to move to and stay at the Port, providing employment opportunities for the broader Stockton community. If these customers face higher operating costs, they may relocate to other ports,

including out of state ports, such as the Port of Seattle. Providing employment opportunities is particularly important because the City of Stockton faces persistently high levels of unemployment. During the first compliance period, unemployment in the City of Stockton went from 19.3% (January 2011) down to 12.5% (December 2013). This is consistently higher than the statewide average, which went from 12.6% to 8.0% over the same time period.[1]

In addition to meeting these rate goals, the Port must also maintain certain levels of reserves. This is necessary to ensure that that the electric utility is a viable part of the Port's overall operations and can continue to operate. If the Port cannot maintain sufficient minimum operating reserves or if the Port cannot provide rates that are sufficiently lower than the surrounding investor owned utility, and then it is very likely that the Port would cease to operate the electric utility.

The Board has given Port Staff the authority to implement these two policies. Based on this direction, the Port has established a target of setting rates that are no higher than 95% of PG&E rates and a minimum reserve policy of 10%. Therefore, the Port implemented its cost limitation in a manner that meets both of these goals.

As a part of a two tier cost limitation rule, at the beginning of each fiscal year budget cycle, the Port reviews its prior year operating reserve and electric rate performance. Then the Port sets its electric budget and commercial/industrial rates to reflect costs and be at or below ninety-five percent (95%) of the local IOU's similar commercial/industrial rates with an operating reserve at or above 10%. Therefore, upon adoption of the FY budget the retail rates and associated cost limitations included in the budget/rate assumptions are approved by the Board for that year.

The cost limitation equation would be the lesser of:

Limit 1 (year+1) = [Revenue(year) / Expense(year) - .95(Comp Rate(year); or

Limit 2 (year+1) = [Revenue(year) – Expense(year) / Revenue(year)≥ 10%, if not, Limit 2=$0

b. Is the cost limitation set at a level that prevents disproportionate rate impact?

Yes. As described above, the Port provides economic development in an economically disadvantaged region of the state. If the Port raises electric rates too high, it can drive customers to other ports, including ports in other states. Because of these economic conditions, the Port's customers and the Stockton community are disproportionally impacted by electric rate impacts. Further, raising rates too high could lead to the Port no longer being able to operate an electric utility and ceasing operation and reducing its ability to attract additional tenants. The Port's cost limitation is set at a level that maintains competitive rates with PG&E and allows the Port to meet its minimum operating reserves.

[1] Bureau of Labor Statistics

2. ***Additional information needed to determine which factors the Port relied upon when determining its cost limitation.***
    a. ***Did the Port rely on its RPS procurement plan in adopting a cost limitation?***

Yes, each year of CP1, the Port incorporated the on-going implementation costs of its proposed local RPS projects within its adopted budget/rates. If the prior year's financial results indicated the need for a rate adjustment or the rate target was exceeded or the operating reserve target was not met, the Port did not spend additional funds on RPS compliance for that year. In 2010, 2011 and 2012 the Port's rates exceeded the cost limitation and the operating reserve target was not met. For 2013 the Port's rates did not exceed the cost limitation. (see Table 4, lines 7 and 16)

3. ***Additional clarification needed to determine whether the Port ensured that the costs of all procurement credited toward achieving the RPS were counted toward the limitation.***
    a. ***Does the $76,000 the Port reported include all RPS procurement expenses?***

No. Upon further review, during CP1 the Port expended approximately $113,000 for work toward RPS compliance on:

Consulting studies
Engineering
2 PG&E System Impact Studies
REC purchases
WREGIS participation
20% for Port staff A&G

If the Port had purchase sufficient PCC1 and PCC3 RECs for the 2011-2013 period from the developing California market, the total cost would have been approximately $414,000 for RECs plus energy (or $195,000 for RECs only) plummeting the Port's operating reserves to below 3% for the overall period.

Table 2

Port of Stockton

REC Purchase Costs Impact On Operating Reserves

	CY11	CY12	CY13	CY 11-13 Total
Total REC Optional Cost	**$ 109,408**	**$141,539**	**$ 162,948**	$ 413,895
New Operating Reserve	$(23,745)	$ 10,976	$ 205,183	$ 192,414
	-1.2%	0.5%	7.1%	2.7%

b. The reported expenses appear to cover years 2010-2015; however, the first compliance period is only 2011-2013. Please clarify whether additional year expenses are included in the RPS procurement expenditures, and if so, please separate the RPS expenditures that were counted toward the first compliance period.

The Port has a fiscal year accounting system and Table 3 attempts to capture the Port's CP1 expenses by year.

Table 3

Conversion from Fiscal to Calendar Year RPS Expenses

2011	2012	2013	Total
$ 59,080	$ 12,953	$ 41,898	$ 113,931

4. ***Additional information needed on the cost limitation in dollars.***

a. ***Please clarify if the Port's cost limitation in dollars is equal to the Port's RPS procurement expenditures. If not, please report the cost limitation in dollars.***

From 2011 to 2013, the Port stayed within its annual adopted budget and rate plan. The Port's cost limitation was determined based on actual average rate performance for the prior year and the operating reserve target. The cost limitation in dollars is calculated by determining the rate difference to the target rate and multiplying the difference by the retail kWh sales. (see Table 4, lines 7, 16)

5. ***Additional information is needed to clarify that procurement expenditures do not include any indirect expenses, including imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades, or the costs associated with relicensing any POU-owned hydroelectric facilities.***

    a. ***Please clarify whether expenses associated with the staff payroll tax are or are not indirect costs.***

The Port's project costs include the direct costs of project design/interconnection engineering, environmental/site work, project consulting, Port staffing and several PG&E system impact studies. Indirect costs associated with imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades, or the costs associated with relicensing any hydroelectric facilities were not included. Additional applicable costs associated with power supply along with the solar project development costs were included in the Port's adopted annual fiscal budget.

The A&G staffing number reflects a proxy for the day-to-day direct involvement of Port staff that worked on the development of the solar projects and is not considered by the Port as indirect costs.

6. ***Additional information needed about actions taken in response to RPS procurement expenditures meeting or exceeding the cost limitation.***

    a. ***Did the Port meet or exceed its cost limitation?***

Yes, in 2010, 2011 and 2012 the Port's retail rate levels exceeded the cost limitation target and the operating reserve targets were not met for RPS compliance expenditures consideration in the next year's fiscal budget. In 2013 the Port's retail rates did not exceed the cost limitation and the operating reserve target was met and therefore, RPS expenditures to purchase RECs from a more mature California market were achieved in 2014. When the rate target was exceeded and the operating reserve target not met, the Port did not spend additional funds on RPS compliance for that year in CP1. (see Table 4)

    b. ***If the Port did not meet its cost limitation, please explain why.***

The Port exceeded its cost limitation and operating reserve limit in years where it was engaged in solar project development, i.e. 2010 through 2013. In 2014, when it met the RPS requirements through the purchase of RECs, the Port did not exceed its cost limitation.

Table 4

Port of Stockton
Cost Limitation Review

		FY10	FY11	FY12	FY13
1	Port Retail Revenue	$ 1,411,684	$ 1,485,932	$ 1,733,301	$ 2,050,356
2	Retail kWh sales	8,759,471	9,166,867	10,972,169	13,638,257
3	Port Avg Rate	$ 0.1612	$ 0.1621	$ 0.1580	$ 0.1503
4	Comp. Avg Rate	$ 0.1690	$ 0.1634	$ 0.1552	$ 0.1746
5	95% of Comp. Rate	$ 0.1605	$ 0.1553	$ 0.1474	$ 0.1659
6	Port above 95% target	$ 0.0006	$ 0.0068	$ 0.0106	$ (0.0155)
7	$ above 95%	$ 5,495	$ 62,599	$ 116,023	$ (211,911)
8	Percent off target	0.39%	4.21%	6.69%	-10.34%
9	Operating Reserve	1.9%	2.4%	6.2%	11.1%
		CY10	**CY11**	**CY12**	**CY13**
10	Retail Revenue	$ 1,478,677	$ 1,549,425	$ 1,926,274	$ 2,216,330
11	kWh sales	9,003,845	9,725,125	12,581,228	14,484,272
12	Port Avg Retail Rate	$ 0.1642	$ 0.1593	$ 0.1531	$ 0.1530
13	Comp. Avg Rate	$ 0.1690	$ 0.1634	$ 0.1552	$ 0.1746
14	95% of Comp. Rate	$ 0.1605	$ 0.1553	$ 0.1474	$ 0.1659
15	Port above 95% target	$ 0.0037	$ 0.0041	$ 0.0057	$ (0.0129)
16	$ above 95%	$ 33,258	$ 39,412	$ 71,823	$ (186,272)
17	Percent off target	2.25%	2.54%	3.73%	-8.40%
18	Operating Reserve	2.7%	4.3%	6.9%	12.7%

Port of Stockton
Response to September 5, 2017 Data Request

1. Did the Port adopt its RPS procurement plans under resolution? If so, please submit a copy of the final resolutions under which they were adopted. If not, how were the RPS procurement plans approved by the Port's governing board? (If there are minutes, or any other documentation showing adoption, please provide).

The Port's Commission delegated the operation of the electric utility to the Port Director in 2010 by Resolution #7681 (attached) who has implemented the necessary provisions of the RPS Standard. The 2012 Plan was made available to the Port's tenants (electricity customers) in late November 2012 through a notice to the tenants (attached). The public hearing to go over the plan and receive comments was conducted on Dec 20, 2012.

The overall implementation of the plan was reported to the Port Commission during the FY2013/14 Budget consideration process conducted 2ndQ 2013 and approved by the Commission on June 3, 2013.

2. The Port's RPS procurement plan (and update) does not discuss optional compliance measures (cost limitations and delay of timely compliance). Did the Port adopt/approve any other versions of the RPS procurement plans during Compliance Period 1 that describe optional compliance measures, or was the application of optional compliance measures left entirely to the discretion of the utility director?

The only Procurement Plan approved during Compliance Period 1 is the version dated November 20, 2012, which is currently posted to the CEC's website. The application of optional compliance measures was left to the discretion of the utility director, based on the Board's direction and long-standing policies provided during Commission Meetings.

3. Did the Port take reasonable measures to procure cost-effective distributed generation and allowable unbundled RECs? (Section 3206 (a)(2)(A)(2)(iv).) Specifically, were any of the project proposals that the Port considered (and pursued) distributed generation, such as the 500 kW rooftop solar system or the 1.5 MW ground based solar system? If not, why? (For example, were they not cost effective?)

The Port did take reasonable actions to procure cost effective distributed generation and allowable RECs. As described in the Port's procurement plans, the Port expended significant effort and funds in attempting to develop a local renewable project. Ultimately, the Port determined that the local project options were not cost-effective and exceeded market prices by a significant margin. The Port also procured PCC3 during CP1.

4. Clarification on Table 2.
    a. We tried to replicate the calculation of **(A)** based on this description: "The cost limitation in dollars is calculated by determining the rate difference to the target rate [95% of competitor rate] and multiplying the difference by the retail kWh sales".

However, we couldn't exactly match the numbers. Please walk us through how the entries in **(A)** were derived.

Sample Year 2011:

	Calculation	Value	Notes
(A) Retail Revenue		$1,549,425	
(B) kWh Sales		9,725,125 kWh	
(C) Port Avg Rate	(A)/(B)	$0.1593	
(D) Comp Avg Rate		$0.1634	
(E) 95% Rate	(D) * 0.95	$0.1553	
(F) Rate Difference	(E) - (C)	$0.0041	Port's rate exceeds the 95% target
(G) Cost Limitation	(F) * (B)	$39,412	If this amount is negative, then the port can spend up to that amount.
(H) Operating Reserve		4.3%	Port's Reserves are below the 10% target.

Result: Port's Rates are above the 95% test and the Operating Reserve is less that 10%, therefore the cost limitation is zero.

b. We added a line to the Table **(B)** to attempt to clarify the relationship between the cost limitation rules, how they translate to the cost limitation in dollars, and what the RPS budget was. Based on our understanding of the rules, the RPS budget was $0 for each year of the compliance period. In 2014, the RPS budget would have been the difference in dollars ($186,272). Please confirm if this understanding is correct.

	[Calendar Year 2010]	[Calendar Year 2011]	[Calendar Year 2012]	[Calendar Year 2013]
[Port] Retail revenue	$1,478,677	$1,549,425	$1,926,274	$2,216,330
[Port] kWh sales	9,003,845	9,725,125	12,581,228	14,484,272
Port [Average] Retail Rate	$0.1642	$0.1593	$0.1531	$0.1530
[Competitor Average] Rate	$0.1690	$0.1634	$0.1552	$0.1746
95% of [Competitor] Rate	$0.1605	$0.1553	$0.1474	$0.1659
[Rate difference between Port Rate and 95% of Competitor Rate]	$0.0037*	$0.0041*	$0.0057*	$(0.0129)
(A) [Difference in dollars]	$33,258	$39,412	$71,823	$ (186,272)
(B) [Cost Limitation in dollars]	n/a	$0	$0	$0
Percent off target	2.25%	2.54%	3.73%	-8.40%
Operating Reserve	2.7%	4.3%	6.9%	12.7%
[*Cost limitation triggered (emphasis added by Energy Commission staff)]				

Your understanding is correct. In 2014, the Port was able to purchase sufficient RECs to be RPS compliant for approximately $81,000 since the REC market had matured and the cost had gone down considerably.

5. The latest response estimated the cost of full RPS compliance as follows: "If the Port had purchase[d] sufficient PCC1 and PCC3 RECs for the 2011-2013 period from the developing California market, the total cost would have been approximately $414,000 for RECs plus energy (or $195,000 for RECs only) plummeting the Port's operating reserves to below 3% for the overall period" (p. 4.). However, the previously submitted spreadsheet calculating the cost of purchasing PCC1 and PCC3 RECs estimated a cumulative REC cost of $107,010. Please clarify which estimate is correct.

The previously submitted spreadsheet calculated the cost of full compliance based on Compliance Period 2 REC prices and only provided the net cost of the procurement. The revised estimate is based on Compliance Period 1 procurement prices and includes both the total cost and net cost.

PORT OF STOCKTON

Phone: (209) 946-0246

Fax: (209) 465-7244

April 27, 2012

Lorraine Gonzalez
California Energy Commission
1516 9th Street, MS-45
Sacramento, CA 95814

Re: Comments on CEC-300-2012-001-SD, 33 Percent Renewables Portfolio Standard, Pre-Rulemaking Draft Regulations

Dear Ms. Gonzalez,

The Stockton Port District appreciates the opportunity to provide comments regarding the 33 Percent Renewable Portfolio Standard Pre-Rulemaking Draft Regulations and the California Energy Commission (CEC) conference conducted by WebEx on April 19, 2012.

Background

The Stockton Port District (Port) is located in Stockton, California with its retail electric utility operating on Rough & Ready Island. Located in San Joaquin County, the Port as well as several other Central Valley Counties have been in the epicenter of the 2008 California housing and foreclosure bubble and still has not recovered. The February 2012 County unemployment rate of 16.6% (US Bureau of Labor Statistics) continues to reflect this environment. The City of Stockton is currently in mediation with its creditors, a step required by AB506, prior to filing for bankruptcy. The Port is the one bright spot in the Central Valley economy that has provided jobs and income to the Stockton area.

Having less than 2,000 customers it is generally referred to as a micro-utility. Annual 2011 retail sales were 9,725 MWhs resulting from sales to commercial and industrial customers with no residential sales. Its 2011 annual peak occurred in December 2011 at 3,125 kW.

Its service area is surrounded by the Pacific Gas and Electric Company with their transmission and distribution lines crossing Rough & Ready Island. As such the utility is in a unique competitive position with PG&E. It must maintain competitive retail rates with PG&E in order to retain its commercial/industrial customer base and attract new industry.

Discussion Points

Post Office Box 2089 • Stockton, CA • 95201-2089 • E-mail: portmail@stocktonport.com
Administration Office: 2201 West Washington Street • Stockton, CA • 95203 • Web Page: www.portofstockton.com

One Size Compliance Standard - During the course of the April 19, 2012 meeting it was emphasized by the Publically Owned Utility (POU) participants that each Board or Commission would decide the implementation of the Renewable Portfolio Standard (RPS) that best fit their utility. This is consistent with Public Utilities Code (PUC) 399.15 and 399.30 (a). It was also emphasized that one method of measuring compliance may not fit all utilities; hence one size will not fit all. This especially true when it comes to comparing the large investor owned utilities to the smaller POUs. The California Public Utilities Commission recognized this size difference in their Decision 05-11-025 regarding their rulemaking to implement the Renewable Portfolio Standard (§C, pg.7). We do not dispute the applicability of the RPS requirement to the POUs only the concept that one set of CEC developed implementation standards will permit the CEC to determine compliance with the PUC. Each POU will determine its best manner of implementation, consistent with the RPS.

Utility Size and Impact on the Renewable Generation Market – California IOUs and POUs have a wide range in size. In 2010 approximately 85% of California retail electricity sales were made by the five largest utilities; PG&E, SCE, SDG&E, SMUD, and LADWP. The remaining 46 small to medium size IOU and POUs supply the remaining 15% of the market and, functionally, can have little overall impact on the development of renewable generation in California. The largest utilities have the financial and staff resources to pursue multiple, large, and geographically separate generating projects that give them an advantage in attracting capital to pursue new projects. Table 1 provides the comparison of size for the top eight IOU and POUs compared to the Stockton Port District.

Table 1. 2010 Investor and Publically Owned Electric Utility Retail Sales

Utility	Percent of Statewide Retail Sales (%)
Pacific Gas & Electric	32.670
Southern California Edison	31.771
Los Angeles Dept. of Water & Power	8.863
San Diego Gas & Electric	7.531
Sacramento Municipal Utility District	3.979
City of Anaheim	1.387
Imperial Irrigation District	1.248
Silicon Valley Power	1.132
Port of Stockton	0.005
All Others	11.414
Total	100.000

Source: 2010 California Electricity Consumption Database

The Port with .005% of the State's retail electricity sales can have little impact on the generation market.

Regulatory Burden – In 2010 the Port, in conjunction with a developer, commenced the studies and design for the construction of a photo voltaic energy project that would give the Port the ability to meet its RPS requirements. The Port had engaged consultants and engineers to assist them with the implementation of the project. The Port and its developer undertook significant expenditures of resources; PG&E had completed the System Interconnect Study and the Port and its developer were ready to start the PG&E Facilities Study and engage the California Independent System Operator (CAISO) to include the project in their 2011 Deliverability Study. Because of a CAISO Tariff issue, the CAISO rejected the inclusion of the project in its 2011 Deliverability Study and suggested waiting until the issue is resolved. As a result the developer chose not to continue with the project.

This is not just a small problem for a micro utility. The expenditure of significant resources to start a project that leads nowhere is a problem for all utilities. However, for the micro utility it cannot just pick up its toys and move to another project or have another party pick up where the other left off. The cost of developing a project relative to the micro utility's revenue stream is many times a larger ratio then that of the three mega-IOUs. Attempting to develop multiple fall back projects to accommodate schedule delays or project alternatives becomes a significant burden to the POU's revenue requirement as well as the limited staff that most small POUs have. The legislature recognized the disproportionate impact of regulation on small investor owned utilities and codified it in PUC §2780.1 (a). This is the same disproportionate financial impact of the RPS and requires a different approach to micro utilities.

Financial Implications – The main issue for the Port is the revenue requirement for setting competitive retail electric rates. Inclusion of renewable resources in the micro utility's portfolio can have a significant negative impact on rates. Current conventional power purchased in the California market is about ½ of that of renewable PV projects. The Port's ability to attract and retain industry in the Stockton area and Rough & Ready Island is partially dependent upon providing competitive rates with PG&E. Inclusion of higher cost power in rates will put competitive pressure on the Port from PG&E; bottom line - the challenge to the Port is the rate impacts. PUC §399.15 (f) recognizes the need for cost containment in the procurement of renewable resources ". . . without exceeding a de minimis increase in rates . . ." for the IOUs. The Port recommends that the CEC recognize this competitive aspect in its rule making for POUs.

Flexible Compliance - As stated above the Port believes that the CEC has the ability to promulgate regulations that are flexible enough to accommodate the wide differences in POUs. PUC §399.30 discusses the many considerations that a POU regulatory body can consider as they implement the regulations. PUC 399.30 (h), (i), (j), and (k) are also examples where the PUC provides alternative methods of implementation for certain utilities. PUC 399.18 goes further with regard to alternative treatment for certain small IOUs. The CPUC, in Decision 05-011-025 (IX Conclusion of Law, 3), recognized utility size as a major reason for a different treatment in the manner of implementation. The Port recommends that the Commission consider a wide spectrum of implementation options for their regulations.

Proposal

Micro utilities have a significant uphill assignment in meeting the RPS at described in PUC§399.11 through 399.31. The Port recommends that the Commission consider an alternative method of compliance with the intent of the RPS for micro utilities. PUC §399.30 (b) and (c) establish "compliance periods" leading up to 2020 setting the amount and types of renewable energy products to be used by the POU in meeting its RPS requirements. The amounts of products are to be consistent with PUC §399.16 which sets the amounts of renewable power permitted from the three categories of renewable products. Category 3 covers Renewable Energy Credits (RECs). PUC §399.12 (h) (1) defines RECs as:

> "Renewable energy credit" means a certificate of proof associated with the generation of electricity from an eligible renewable energy resource, issued through the accounting system established by the Energy Commission pursuant to Section 399.25, that one unit of electricity was generated and delivered by an eligible renewable energy resource.

PUC §399.16 (c) (2) permits not more than 25 percent RECs in the compliance period ending in 2015 reducing to 10% starting in 2017.

PUC §399.25 (c) requires the Commission to:

> Establish a system for tracking and verifying renewable energy credits that, through the use of independently audited data, verifies the generation of electricity associated with each renewable energy credit and protects against multiple counting of the same renewable energy credit.

Such a system exists as the Western Renewable Energy Generation Information System (WREGIS) and is referenced in the draft regulations. Since the WREGIS captures and accounts for the renewable characteristics of qualifying generation, the use of RECs can be tracked and traced to actual renewable generating resources avoiding any kind of improper accounting.

The Port proposes that for micro utilities the Commission find that they have different financial and personnel resources than the largest utilities and that, although they are required to meet the same RPS quantities as defined in PUC §399.30 as other utilities, the manner by which they do can include a full reliance on the WREGIS REC market.

We believe this proposal will not negatively impact the REC market but rather enhance it due to greater participation. It also provides a viable means for micro utilities to meet the RPS requirements.

The Stockton Port District appreciates the opportunity to comment on the CEC's Pre-Rulemaking Draft Regulations and supports a continuing dialogue to develop regulations that will benefit all of California. If you have any questions please feel free to contact me at (209) 946-0246 or Chris Kiriakou at (209) 634-8105.

Sincerely,

Juan G. Villanueva
Projects & Contract Administration/DBELO Manager

CC: Richard Aschieris
Steve Escobar
Jeff Kaspar
Chris Kiriakou

The Stockton Port District	Shell Energy North America (US), L.P.
Contract ID:	Contract ID:
Deal Maker: Juan Villanueva	Deal Maker: Robert Pierce
Phone: 209-946-0246	Phone: 509-688-6063
Fax : 209-464-7244	Fax: 858-320-2674

CONFIRMATION AGREEMENT
Green Attributes (RECs Only – Bucket 3) – WSPP Agreement

This Confirmation Agreement ("Confirmation" or "Agreement") is entered into December 21, 2012 ("Effective Date") by and between **The Stockton Port District** ("Stockton" or "Buyer") and **Shell Energy North America (US), L.P.** ("Shell Energy" or "Seller"); each individually a "Party" and collectively the "Parties", regarding the purchase and sale of products under the terms and conditions below.

Master Agreement:	EEI Master Power Purchase and Sale Agreement between the Parties dated October 13, 2010 (the "EEI Master Agreement").
Transaction:	Buyer is buying Renewable Energy Credits ("RECs") from Seller and Buyer shall take title to such during the Delivery Term herein.
Project:	The RECs sold by Seller to Buyer are produced by Phase III of the Nine Canyon Wind Project that: (i) is certified with the CEC and qualifies as an Eligible Renewable Resource, as such term is defined in Public Utilities Code Section 399.12 or Section 399.16, (CEC number 60803A), (ii) is located near Finley, Washington, (iii) is a 32.2 MW phase of a the larger Nine Canyon wind facility, and (iv) (a) Phase III commenced commercial operation after January 1, 2005, and (b) is interconnected to the BPA transmission system (the "Project").
Product:	Green Attributes sourced by the Project, as such Product is described in the Code Pub. Util. Code §399.16(b)(3) and as further defined in CPUC D.11-12-052 (Decision Implementing RPS Portfolio Content Categories).
Seller:	Shell Energy
Buyer:	Stockton
Delivery Term:	The Delivery Term of this Transaction shall commence upon the Effective Date and shall continue through December 31, 2013, and until the Parties have fulfilled all obligations with respect to the Transaction, including the transfer of all RECs via WREGIS Certificates to Buyer and the payment of amounts due pursuant to this Confirmation.
Vintage:	Calendar year 2013.
Contract Quantity:	607 RECs
RECs Contract Price:	$1.50 per REC.
Delivery Point:	Title to RECs shall transfer from Seller to Buyer through WREGIS.
Transfer Date:	Unless otherwise mutually agreed, on or before November 30, 2013.
Change in Law:	If any action by the CPUC or any state, federal or local Governmental Authority or agency occurs after the Effective Date hereof and the result of such action is that Buyer is precluded from using the

Product purchased herein to satisfy the California Renewables Portfolio Standard requirement ("Change in Law") Buyer may elect to terminate this Confirmation by delivering to the other Party written notice of such termination not later than 60 days following the effective date of the Change in Law. In the event Buyer does not exercise its right to terminate this Confirmation due to a Change in Law within such 60 day period, Buyer may not thereafter terminate this Confirmation due to the Change in Law. A termination of this Confirmation due to a Change in Law shall be effective upon the delivery of written notice therefore and thereafter:

(i) all obligations to Deliver RECs not then already transferred by Seller to Buyer shall be terminated and Seller shall have no obligation to make any further deliveries, and Buyer shall have no obligation to accept any transfer, of Green Attributes;

(ii) If Buyer refuses to accept Delivery of the RECs due to the Change in Law, neither Party shall be liable for damages;

(iii) neither Party shall have any further obligations to the other hereunder with respect to RECs not Delivered due to a proper termination in accordance with the foregoing.

Title Transfer and Indemnity:

Sections 10.3 and 10.4 of the EEI Master Agreement shall apply only to Power Products. With respect to RECs, title transfers from Seller to Buyer upon the completion of both Delivery and payment for the RECs.

Mutual Representations and Warranties. During the Delivery Term, each Party represents and warrants to the other that: (i) it is an "eligible commercial entity" and an "eligible contract participant" within the meaning of United States Commodity Exchange Act §§1a(11) and 1a(12), respectively, and this Transaction has been subject to individual negotiation by the Parties.

SPECIAL PROVISIONS:

(1) Green Attributes: Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project. [STC 2 - RECs and Green Attributes, Non-Modifiable. D.08-04-009 (3.2)].

(2) Transfer of Renewable Energy Credits: Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the renewable energy credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. [STC REC-1, Non-modifiable D.11-01-025].

(3) Tracking of RECs in WREGIS: Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract. [STC REC-2, Non-modifiable. D.11-01-025].

(4) RECs Settlement: During the Delivery Term, each Party, at its own cost and expense, shall maintain its registration with WREGIS. Each Party shall, at its sole expense, use WREGIS as required pursuant to the WREGIS Operating Rules to deliver and convey (in the case of Seller) and receive/accept (in the case of Buyer) RECs in accordance with WREGIS reporting protocols and WREGIS Operating Rules. Seller shall, at its sole cost and expense, take all commercially reasonable actions and execute documents or instruments necessary to ensure that the RECs to be sold hereunder from the Project can be transferred to Buyer utilizing WREGIS and that the transfer of WREGIS Certificates shall represent the RECs attributable to or associated with such Green Attributes from the Project. Buyer warrants that all necessary steps to allow the RECs transferred from Seller to be tracked in WREGIS will be taken prior to the first delivery under the contract.

(5) Eligibility: Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer

qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. [STC 6, Non-Modifiable D.08-04-009];

(6) Additional Representations and Warranties of Seller.

(i) Seller has not sold the Product or any Green Attributes of the Product to be transferred to Buyer to any other person or entity;

(ii) each REC meets the specifications set forth herein;

(iii) All rights, title and interest in and to the Product are transferred free and clear of any taxes or security interests except for any right or interest by any entity claiming through Buyer.

(7) Payments for RECs. Seller shall invoice Purchaser for the RECs after the WREGIS Certificates for such RECS have been properly transferred to Purchaser's WREGIS account in accordance with the rules and regulations of WREGIS. Purchaser shall pay the RECs Contract Price for the WREGIS Certificates transferred to Purchaser's WREGIS Account not later than ten (10) Business Days following receipt of Seller's invoice subsequent to the transfer of the RECs.

(8) Regulatory: The Parties intend the rates, terms and conditions of service specified in this Confirmation to remain fixed throughout the Delivery Term of this Confirmation regardless of any changes in underlying costs that would justify a change in rates under traditional cost of service principles. Neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Confirmation, notwithstanding any subsequent changes in Applicable Law, its costs of service or market conditions that may occur.

(9) Governing Law. For purposes of this Confirmation Article 10.6, Governing Law, of the EEI Master Agreement is amended by inserting at the end thereof the following: "Notwithstanding the foregoing, this Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each Party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Agreement. [STC 17, Applicable Law, Non-Modifiable D.08-04-009].

(10) Liquidated Damages. For purposes of this Confirmation only, Article 4 of the EEI Master Agreement is amended by inserting at the end thereof the following: In lieu of and not in addition to the damages provided in this Article 4, in the event that Seller's failure to deliver is due to DSO 216, Buyer's damages shall be limited to the lower of Buyer's actual loss or two times the Contract Price for the affected Contract Quantity.

(11) RPS Confidentiality. Either Party shall be permitted to disclose the following terms with respect to such Transaction: Party names, resource type, delivery term, project location, and project capacity.

DEFINITIONS / INTERPRETATIONS: For purposes of this Confirmation, the following definitions and rules of interpretations shall apply:

"Applicable Law" means all legally binding constitutions, treaties, statutes, laws, ordinances, rules, regulations, orders, interpretations, permits, judgments, decrees, injunctions, writs and orders of any Governmental Authority or arbitrator that apply to the Applicable Program or any one or both of the Parties or the terms hereof.

"California Program", "California Renewables Portfolio Standard" or "California RPS" means the renewable energy program and policies, codified in California Public Utilities Code Sections 399.11 through 399.20 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

"CEC" means the California Energy Commission or its regulatory successor.

"CEC Certification" means, if applicable, the certification of the renewable resource by the California Energy Commission as specified in the Renewables Portfolio Standard Eligibility Guidebook as eligible toward meeting the state's Renewables Portfolio Standard pursuant to Public Utilities Code Sections 399.11, et seq. and Public Resources Code Section 25741.

"CPUC" means the California Public Utilities Commission or its regulatory successor.

"Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to RECs, as well as: (1) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere;[1] (3) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Buyer to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Buyer's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. Green Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project. [STC 2, RECs and Green Attributes, Non-Modifiable.]

"Governmental Authority" means any international, national, federal, provincial, state, municipal, county, regional or local government, administrative, judicial or regulatory entity operating under any Applicable Laws and includes any department, commission, bureau, board, administrative agency or regulatory body of any government.

"HE" means the hour ending.

"PPT" means Pacific prevailing time.

"REC" or "Renewable Energy Credit" means the right to claim Green Attributes attributable to the generation of electric energy from renewable energy resources. RECs are measured in one megawatt-hour increments and evidenced by a WREGIS Certificate. A REC includes all Green Attributes arising as a result of the generation of electricity associated with the REC.

"STC" stands for Standard Terms and Conditions of the CPUC relating to purchase and sales of Green Attributes.

"Vintage" means the period in which the REC was or will be created by the Project.

"WECC" means the Western Electricity Coordinating Council or its successor organizations.

"WREGIS" means the Western Renewable Energy Generation Information System.

"WREGIS Certificates" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

"WREGIS Operating Rules" means those operating rules and requirements adopted by WREGIS as of June 4, 2007, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

Please confirm that the terms and conditions stated herein accurately reflect the agreement reached by Buyer and Seller by signing and returning by facsimile to Seller at (858) 320-2674.

[SIGNATURE PAGE FOLLOWS]

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

IN WITNESS WHEREOF, the Parties have signed this Confirmation effective as of the Effective Date.

The Stockton Port District	Shell Energy North America (US), L.P.
By:	By:
Name: Steve Eschen	Name: BETH BOWMAN
Title: Deputy Port Director	Title: Sr. Vice President

[redacted]

Account Holder	SubAccount	Subaccount ID		[redacted]	Retirement Reason
Stockton Port District	2013 CA RPS PCC3		4195		Out-of-State/Province Resource

[redacted]			[redacted]	[redacted]
State/Province	Certification #	Compliance Period	[redacted]	WREGIS GU ID
CA	60803A	2013	[redacted]	W697

Generator Plant-Unit Name	Fuel Type	Vintage Year/M	Certificate Serial Numbers	Quantity
Nine Canyon Wind Project - Nine Canyon Phase 3	Wind	2013/02	697-WA-80881-2714 to 3320	607

eTags	Duration - Start Date	Duration - End Date	AZ	BC	CA	CO	MT	NV	NM	TX
	2/1/2013	2/28/2013	No	No	Yes	No	No	No	No	No

WA	OR	AB	UT	Green-e Energy Eligible	Ecologo Certified	Hydro Certification	SMUD Eligible
No	Yes	No	No	Yes	No	No	No

[redacted]

eTag Matched	[redacted]	Action Date	[redacted]
No		7/1/2014 14:44	

1565 E. Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
chris_k@cornerstoneconsulting.biz

CORNERSTONE CONSULTING

Memo

To: Juan Villanueva

From: Chris Kiriakou

CC: Janice Dias

Date: January 10, 2012

Re: WREGIS Registration

As part of the Port of Stockton's power supply plan and RPS Procurement compliance plan the Port has contracted with Shell Energy NA for Renewable Energy Certificates (RECs) in 2013 (607 RECs) and 2014 (388 RECs). One REC equals 1,000 kWhs. In order for Shell to transfer the RECs to the Port and the Port to use them the Port must be an Account Holder in the Western Renewable Energy Generation System (WREGIS). WREGIS is a web based computer database that tracks the renewable and environmental attributes of renewable generation and their associated RECs, their transfer and ultimate retirement. Following is a brief description of the registration process for participation in WREGIS.

1. Complete the Online Registration. (http://www.wecc.biz/WREGIS/Pages/AccountHolderRegistration.aspx)
2. Become familiar with the WREGIS Operating Rules. (Attached. These cover the set up and use of accounts by the Account Holder; Active, Retirement, Reserve and Export Subaccounts and the creation of RECs by generating entities. It also includes the Interface Control Document which covers the details of the forms in use by WREGIS)
3. Read and sign the WREGIS Terms of Use and the legal forms and agreements pertinent to your user type. (The User Type is Municipal Utility and a completed Agreement Attached)
4. Using the WREGIS Fee Estimation Table, calculate your Account Holder fees. Checks should be made payable to: WREGIS Administrator. (The fee is $1,500 Annually plus $0.01/REC when retired. Fee Schedule Attached)
5. Mail completed registration packet to the WREGIS Administrator. A complete packet will include the signed legal agreements, applicable attestations, and any other required documents, along with the fee payment effective January 1, 2008. No payments due for annual fees until that time. Please mail the completed registration packet to the attention of the WREGIS Administrator at:
   155 North 400 West, Suite 200
   Salt Lake City, UT 84103
6. Once online registration is complete and the registration packet is received by the WREGIS Administrator, WREGIS Staff will review the signed legal agreements, attestations, proof of essential characteristics documents and online registration materials. If materials are

incomplete or additional information is required, the WREGIS Administrator will notify the designated contact.

7. Once registration materials are complete and validated, an email notification describing account activation will be sent to the designated Account Holder email or Agent email address provided during registration.
8. Account Holder may begin registering generating units, establishing reporting entities for generation data submittal and using all other functions of the system available to their account holder type.
9. Registration Process completed

In order for the Port to become an Account Holder the Port staff should complete the On-Line Registration form, review the Operating Rules and sign the Terms of Use Agreement. I have briefly reviewed both the Operating Rules and the Terms of Use Agreement and they are satisfactory. The cost for becoming a participant in WREGIS is the annual $1,500 fee plus the cost of retirement of the RECs which is less than $10. The FY 2012/13 Budget included $22,104 for RECs and associated costs based on RECs at $10/REC. Through bidding the Port was able to purchase RECs for $1.50/REC leaving sufficient funds to cover the WREGIS costs.

Recommendation

It is recommended that the Port staff complete the On-Line Registration process, review the Operating Rules and Terms of Use, execute the Terms of Use agreement and mail the registration package along with a check for $1,500 to WREGIS at the address above.

Attached:
WREGIS Operating Rules
WREGIS Terms of Use Agreement
WREGIS Fee Matrix

Document name	**WREGIS Account Holder Registration Agreement**
Category	( ) Regional reliability standard ( ) Regional criteria ( ) Policy ( ) Guideline (x) Report or other ( ) Charter
Document date	June 22, 2007
Adopted/approved by	
Date adopted/approved	August 6, 2008
Custodian(entity responsible for maintenance and upkeep)	WREGIS
Stored/filed	Physical location: Web URL:
Previous name/number	
Status	( ) in effect ( ) usable, minor formatting/editing required ( ) modification needed ( ) superseded by _____ (x) other –updates for review/approval _____ ( ) obsolete/archived)

Western Renewable Energy Generation Information System

WREGIS

Account Holder Registration Agreement

(Also referred to as the "TERMS OF USE")

WESTERN ELECTRICITY COORDINATING COUNCIL •
WWW.WECC.BIZ
155 NORTH 400 WEST • SUITE 200 • SALT LAKE CITY • UTAH • 84103-1114 • PH 801.582.0353 • FX
801.582.3918

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ACCOUNT HOLDER REGISTRATION AGREEMENT OR TERMS OF USE

This Account Holder Registration Agreement (Agreement) is entered into on this date March 7, 2013 by and between (enter the legal name of the Account Holder) Stockton Port District having its principal place of business at (address, city, state and zip) 2201 West Washington Street, P.O. Box 2089, Stockton, CA 95201 (Account Holder) and the Western Electricity Coordinating Council (WECC), having its principal place of business at 155 North 400 West, Suite 200, Salt Lake City, UT 84103. The Account Holder Registration Agreement is abbreviated throughout as "Terms of Use" or "Agreement." Capitalized terms used throughout the document have the meanings given when introduced or in Attachment 1 - Definitions.

Recitals

WHEREAS:

1. The Western Renewable Energy Generation Information System (WREGIS) is an independent and automated web-based renewable energy registry and tracking system that receives Data on renewable energy generation, creates merchantable renewable energy certificates ("RECs" or "Certificates"), registers the transfer of Certificates within and without the WREGIS system, and allows reporting on such transfers. When used herein, "WREGIS" is meant to encompass all hardware, software, and interfaces that are used in the operation of and/or that comprise the system and are made available to Account Holders by WECC under this Agreement. A Certificate is created in increments of one megawatt hour (MWh) of reported renewable energy generation.

2. WREGIS covers the same geographic region as the Western Interconnection and WECC. WREGIS will issue Certificates for registered renewable energy Generating Units located within the Western Interconnection and for registered renewable energy Generating Units located in states and provinces within WECC.

3. WREGIS is not a trading system for either RECs or energy but instead emulates a banking system. WREGIS Certificates are the currency of the banking system and may be used to verify compliance with state and provincial policy mandates, and to protect the integrity of voluntary green power markets.

4. WREGIS was a joint effort of the Western Governors' Association, the Western Regional Air Partnership and the California Energy Resources Conservation and Development Commission (Energy Commission),

collectively known as the Founding Sponsors. WECC agreed to be the institutional home of WREGIS.In March 2012, when the Founding Sponsors' sponsorship of ended, WECC became the sponsor of WREGIS and continued its operations within WECC. WREGIS is intended to be financially self-supporting through fees paid by Account Holders.

5. A goal of WREGIS is to provide accurate and reliable Certificates reflecting actual renewable energy generation. WREGIS is intended to be policy neutral and will not determine whether Certificates are eligible for particular regulatory programs or voluntary markets.

6. Another goal of WREGIS is to protect against double or multiple counting of the same renewable energy.

7. WREGIS is not intended to establish legal title to Certificates but instead to accurately track who is registered as possessing Certificates. Persons must address any issues regarding ownership or security interests in the Certificates outside of WREGIS.

8. Any person who wishes to use WREGIS must register as an Account Holder and establish an account within WREGIS.

9. All Account Holders must enter into this Agreement with WECC before using WREGIS. Only Account Holders may create or register Certificates.

10. WECC administers WREGIS consistent with WECC's Bylaws, the WREGIS Committee charter and WECC's reliability mission.

11. The WREGIS Committee is a committee of the WECC Board of Directors. WECC operates WREGIS with the advice, guidance, and assistance of the WREGIS Committee as detailed in the WREGIS Committee Charter. The WREGIS Committee represents both industry and governmental interests.

12. The WREGIS Director oversees the day-to-day operations of WREGIS. WECC has contracted with APX, Inc. to provide the software, including maintenance.

13. WREGIS accounts can be accessed only by using the secure WREGIS Website. An Account Holder must be approved by the WREGIS Director, must agree to this Agreement, must abide by the Operating Rules, must follow applicable Interface Control Documents, and must pay the fees required by this Agreement. An Account Holder will be able to access its WREGIS accounts and Data on the WREGIS Website by logging into WREGIS using its username and password.

14. Some Generator Owners or their duly authorized agents may agree with their Balancing Authority for the Balancing Authority to act as their Qualified Reporting Entity in order to report their respective Output to WREGIS. A Balancing Authority Account Holder may report Output on behalf of Generator Owners or their duly authorized agents that have designated the Balancing Authority Account Holder as their Qualified Reporting Entity.

15. This Agreement states the terms and conditions for registering renewable energy Generating Units and establishing an account with WREGIS.

NOW, THEREFORE, acknowledging that the success of WREGIS will depend on the truth, accuracy and completeness of the declarations made below and on these terms and conditions, the undersigned agree and represent that:

(1) Parties

This is a binding contract between the Account Holder and WECC. Account Holder and WECC are individually referred to herein as "Party" and collectively as "Parties."

(2) Acceptance of Terms

a. Account Holder's use of WREGIS (including the secure WREGIS Website located online at www.wregis.org) is subject to the following Agreement (and as it may be modified from time to time).

b. Subject to the provisions of Section 2(e), by accessing its account through the secure WREGIS Website, Account Holder accepts and agrees to be bound by this Agreement. Account Holder's use of WREGIS is governed by the version of the Agreement in effect on the date the WREGIS Website is accessed by Account Holder. Account Holder agrees to comply with the requirements of this Agreement and, in the event of a failure to comply, agrees to be subject to the default and termination provisions of this Agreement. WECC will maintain a copy of the current version of this Agreement on the WREGIS Website.

c. Subject to the provisions of Section 2(e), by signing this Agreement, Account Holder is also subject to the WREGIS Operating Rules in effect on the date the secure WREGIS Website is accessed by Account Holder. Account Holder agrees to comply with the requirements of the Operating Rules and, in the event of a failure to comply, agrees to be subject to the default and termination provisions of this Agreement. Each and all of the

provisions of the Operating Rules are hereby incorporated by reference into this Agreement as though set forth fully herein. WECC will maintain a copy of the current version of the Operating Rules on the WREGIS Website.

d. Subject to the provisions of Section 2(e), by using WREGIS, Account Holder is also subject to the protocols of the Interface Control Documents in effect on the date the secure WREGIS Website is accessed by Account Holder. Account Holder agrees to comply with the requirements of the applicable Interface Control Document and, in the event of a failure to comply, agrees to be subject to the default and termination provisions of this Agreement. Each and all of the provisions of the Interface Control Documents are hereby incorporated by reference into this Agreement as though set forth fully herein. WECC will maintain a current copy of the Interface Control Documents on the WREGIS Website.

e. WECC or its successors in interest, if any, may modify or amend this Agreement, Operating Rules, or Interface Control Documents at any time, upon providing (1) a minimum of 15 days prior written notice to the Account Holder if such modification or amendment is a technical change necessary for the continued operation of WREGIS and, (2) a minimum of 60 days prior written notice to the Account Holder for any other proposed modification or amendment. Such notices shall contain the terms of the proposed modification or amendment. If practicable, such process shall (a) provide for at least a 30-day period for consideration of the proposed amendment prior to its adoption and, (b) afford each Account Holder with a reasonable opportunity to participate in such proceedings. Account Holder agrees that by accessing its account through the secure WREGIS website—after having received appropriate written notice of the modification of the Agreement, Operating Rules, or Interface Control Documents in accordance with this Section 2—Account Holder signifies agreement to be bound by the modified Agreement, Operating Rules, and Interface Control Documents.

f. If at any time Account Holder no longer agrees to this Agreement, the Operating Rules, and the Interface Control Documents—as each is currently written or as they may be modified in the future—Account Holder shall provide written notice to WECC, in accordance with Section 10(c), of its termination of this Agreement and shall cease to access or otherwise use WREGIS and the secure WREGIS Website, but shall be entitled to a final statement of the Account Holder's account and other information reasonably requested by the Account Holder, including an accounting of the number of Certificates attributable to the Account Holder.

(3) Service Description

a. WREGIS is an independent, automated, web-based, renewable energy registry and tracking system that receives Data on renewable energy generation, logs generation Data, allows for the review and/or dispute of Output, uses the Output for issuing WREGIS Certificates and tracks, via Certificates, renewable energy transactions occurring within the Western Interconnection.

b. WREGIS allows for differentiated roles and permissions for various types of authorized Account Holders of the system as to management of accounts, Data access and reporting as more fully specified in the Operating Rules.

c. WREGIS will produce electronic Certificates based on Output. A WREGIS Certificate represents all of the attributes from one MWh of electricity generation from a renewable Generating Unit registered with the WREGIS tracking system. One Certificate will be created for each whole MWh of renewable energy that is produced.

d. Each account will have sub-accounts established to allow the Account Holder to transfer Certificates. The rules on sub-accounts are specified in the Operating Rules.

e. Account Holder agrees that WREGIS does not establish legal title to Certificates in any form. Any issues that might arise regarding the ownership or security interest in Certificates, or whether the transferred Certificate is considered a 'forward contract' under the laws of a state or the laws of the United States, will be addressed by the Account Holder outside of WREGIS. WECC will not address any such ownership issues or have liability with respect to any such ownership issues.

(4) Output Reporting

a. WREGIS issues Certificates only for Output. It is the responsibility of the Generator Owner and/or its agent to supply Output in accordance with the timelines incorporated in the WREGIS Operating Rules. If the Qualified Reporting Entity, designated reporting entity (using protocols described in an Interface Control Document), a Self-Reporting Interface, or Account Holder or its Agents or assigns fails to supply all required Output on registered Generating Units to WECC according to the dates specified in the Operating Rules, the Account Holder and Generator Owner will automatically be notified of the missing Output. The WREGIS Director may request submission of reasonable and consistent supplemental or additional Data from the Account Holder responsible for the Generating Unit in order to secure the missing Output.

b. If the WREGIS Director determines that Data from an Account Holder is required for the determination of compliance by another Account Holder with this Agreement, Operating Rules, or Interface Control Documents; the WREGIS Director shall so notify the Account Holder and the Account Holder shall have 30 days from such notice, or a mutually agreeable extension thereof, to provide the requested Data to the WREGIS Director. An Account Holder may also request the WREGIS Director to request from another Account Holder, Output or Data required for the requesting Account Holder's compliance; however, such a request shall not relieve the Account Holder of any obligations to provide requested Output.

c. If any Data is requested of Account Holders that is not listed in Section 13(b) or Section 13(c), such request will first be submitted to the WREGIS Committee for review and action. The WREGIS Committee will notice and hold a public WREGIS Committee meeting to discuss the request and will make a determination of the confidentiality status of any new Data being requested. If approved, the request is subject to the WREGIS change control procedure as detailed in the Operating Rules.

(5) Authorized Users

a. An Account Holder can be any Person with the capacity to sue or be sued under the law of a state or a federal government. An Account Holder may include one or more of the following types of organizations or entities: Generating Unit owner or representative, Generator Unit aggregator, community choice aggregator, small utility aggregator, investor-owned utility (IOU), municipal utility, rural electric cooperative, irrigation district, electricity service provider, joint power authority, retail marketer, broker, tribal organization, customer-owned utility, public interest organization,

federal marketer/power administration, wholesale marketer, state program director, provincial program director, qualified independent party, Balancing Authority, other load serving entity, or other legal entity.

b. An Account Holder who has account Registration and permissions for an account may designate a Person outside of the Account Holder's organization to serve as an Agent or other authorized user on the account. This is accomplished by the Account Holder submitting a Notice of Agent Designation. The Agent shall have only those WREGIS permissions and privileges as expressly granted by the Account Holder in the Notice of Agent Designation. The Notice of Agent Designation shall not be effective until acknowledgement is issued by WECC. Such Notice of Agent Designation must be revoked by written notification from the Account Holder in the Notice of Agency Termination. In such event, the Account Holder will provide such written notification to WECC and such termination of the Notice of Agent Designation will not be effective until acknowledgement is issued by WECC. Such acknowledgement will be made to the Account Holder by WECC Staff within five business days of WECC's receipt of written notification of revocation of the Notice of Agent Designation.

c. The rights granted herein are granted only to Account Holders and their Agents. In the case of an Agent, the terms of the Notice of Agent Designation specify who is to pay WREGIS fees to WECC. In the case of an assignment of Registration permissions by a Generating Owner, the Notice of Assignment of Registration Rights specifies that the Assigned Account Holder (the one registering the Generating Unit) is to pay to the WECC registration fees, if applicable. If an Affiliate wishes to use WREGIS, it must apply for its own Registration, agree to this Agreement, abide by the Operating Rules, follow the applicable Interface Control Document, and pay the required fees.

d. The rights and obligations of this Agreement shall run to the named Parties and their Agents for those WREGIS permissions and privileges expressly granted to the Account Holder.

e. The Account Holder agrees that any of its employees or Agents to whom the Account Holder has provided access to WREGIS will fully comply with this Agreement, Operating Rules and the applicable Interface Control Documents, and further agrees to make such compliance a condition of any agreement that Account Holder may create for this purpose.

(6) Grant

a. WECC grants to Account Holder, and its authorized agents, a non-exclusive non-transferable license to use WREGIS software at the WREGIS Website subject to this Agreement, Operating Rules and Interface Control Documents in force. Before granting Account Holder access, Account Holder shall (1) complete and submit this Agreement to the WREGIS Director, (2) complete and submit Account Holder Registration Data (on-line after obtaining temporary status to use WREGIS as a Registrant) to the WREGIS Director, and (3) pay the applicable fees due under this Agreement and Operating Rules.

b. Account Holder's use under the license shall be subject to the following limitations:

   (i) Account Holder shall not (a) loan, share, publish, republish, disclose, transmit, display, sell, license, lease or distribute any portion of WREGIS software to any third party, (b) disassemble, decode, decompile or otherwise reverse engineer, copy, reproduce WREGIS software, or (c) loan, share, publish, republish, disclose, transmit, display, sell, license, lease, distribute, disassemble, decode, decompile, reverse engineer, copy, reproduce, or use WREGIS as a basis for a directory or database prepared for commercial sale or distribution. Account Holder shall not modify the format of any WREGIS generated report, but such restriction does not include the information contained therein.

   (ii) Account Holder shall not remove any copyright, trademark, or other proprietary notices contained in WREGIS.

   (iii) Account Holder shall not knowingly infringe or misappropriate WREGIS software.

   (iv) WECC represents and warrants that it has received from software provider, all necessary rights to allow Account Holder to use WREGIS in accordance with this Agreement.

c. WECC reserves all rights in WREGIS not expressly granted to Account Holder in this Agreement. Account Holder acknowledges that the WREGIS software does not belong to Account Holder. Except as provided in this Agreement, Account Holders shall not obtain, have, or retain any right, title, or interest in or to WREGIS or the WREGIS software or any part thereof pursuant to this Agreement.

d. In using the WREGIS Website, Account Holder agrees:

(i) Not to disrupt or interfere with the security of, or otherwise abuse, WREGIS or any services, system resources, accounts, servers, or networks connected to or accessible through the WREGIS Website or affiliated or linked sites;

(ii) Not to disrupt or interfere with any other user's use and enjoyment of the WREGIS Website or affiliated or linked websites;

(iii) Not knowingly to upload, post, or otherwise transmit through or on the WREGIS Website any viruses or other harmful, disruptive, or destructive files;

(iv) Not to copy, use, frame, or utilize framing techniques to enclose any WREGIS or WECC trademark, logo, or other proprietary information (including the images found at the WREGIS Website, the content of any text or the layout/design of any page or form contained on a page and expressly excluding information contained in reports) without WECC's express prior written consent;

(v) Not to use meta tags, cookies, or any other "hidden text" created by Account Holder utilizing the WREGIS or the WECC name, trademark or product name without WECC's express prior written consent;

(vi) Not to "deeplink" to the WREGIS Website without WECC's express prior written consent;

(vii) Not to create or use a false identity on the WREGIS Website;

(viii) Not to attempt to obtain unauthorized access to the WREGIS Website or portions of the WREGIS Website that are restricted from general access or portions of the WREGIS Website that are assigned specific Account Holder access permissions outside of the Account Holder's own access permissions;

(ix) Not to post any material that is knowingly false or defamatory, inaccurate, abusive, vulgar, hateful, harassing, obscene, profane, sexually oriented, threatening, invasive of a person's privacy, or otherwise in violation of any law;

(x) Not to post any copyrighted material unless the copyright is owned or lawfully licensed by Account Holder or by WECC; and

(xi) In addition, Account Holder agrees to comply with all applicable local, state, national, and international laws and regulations, including but not limited to United States export restrictions, that relate to use of or activities on the WREGIS Website.

(7) Fees

Account Holder agrees to pay all applicable Fees, including Annual Fees and Volumetric Fees, collectively referred to herein as the "Fees", that WECC charges for using WREGIS. All Volumetric Fees will be calculated monthly. Fees may change from time to time. WECC may, at its sole discretion, increase or decrease the Fees at any time, upon providing 60 days' prior notice to the Account Holder. WECC shall notify Account Holder of any WECC process to change the Fees by first publishing the notice on the WREGIS Website. If practicable, such process shall (a) provide for at least a 30 day period for consideration of the proposed change prior to its adoption; and (b) afford each Account Holder with a reasonable opportunity to participate in such proceedings. Any changes in the fee structure will be publicly noticed and discussed at a public WREGIS Committee meeting and approved by the WREGIS Committee prior to being implemented. In no event shall any portion of the Fees paid to WECC be prorated or refunded to Account Holder upon termination of the Agreement. Likewise, Account Holder's obligation to pay any and all Fees due to WECC shall survive the termination of such use or access.

a. A schedule of Fees to be charged each type of Account Holder will be posted on the publicly accessible WREGIS Website. Initially, WECC will charge most Account Holders both an Annual Fee and a Volumetric Fee. The fee matrix on the WREGIS Website details which fees each type of Account Holder will be charged.

b. Annual Fees will be calculated in the anniversary month that the account was approved. The full payment of the Annual Fee will be required prior to the WREGIS Director's approval of the New Account Registration.

c. No Annual Fee will be charged to: (1) non-transacting state, provincial, or federal regulators; (2) Qualified Reporting Entities whose sole purpose is to report generation output on behalf of a Generating Unit that is not owned by the reporting entity (e.g., the California Independent System Operator Corporation); and (3) voluntary program directors, such as; Green-e, Low-Impact Hydro, or Ecologo.

d. **Certificate Issuance Volumetric Fee.** WECC shall assess Account Holder a Volumetric Fee for the issuance of a Certificate. Account Holder shall pay a fee per MWh of issued WREGIS Certificates. The Certificate Issuance Fee shall be calculated monthly based on the number of Certificates issued.

e. **Certificate Transfer Volumetric Fee.** WECC shall assess Account Holder a Volumetric Fee for the transfer of a Certificate from one Account Holder to another. The Account Holder initiating the transfer shall pay the Fee on each Certificate transferred to another Account Holder, whether the transfer is scheduled (Standing Order Transfer or Forward Certificate Transfer) or non-scheduled (ad hoc). The Certificate Transfer Fee shall be calculated monthly based on the number of Certificates of which the transfer was initiated by the Account Holder and accepted by the intended recipient.

f. **Certificate Retirement, Reserve, or Exported Volumetric Fee.** WECC shall assess a Volumetric Fee for retiring, reserving, or exporting a Certificate. All Account Holders that retire, reserve, or export Certificates shall pay the Volumetric Fee on each Certificate retired, reserved, or exported. The Certificate Retirement, Reserve, or Export Fee shall be calculated monthly based on the number of Certificates retired, reserved, or exported.

(8) Payments and Taxes

The Fees shall be non-refundable and are due and payable within 30 days from the date of WECC's invoice. Account Holder will pay all applicable sales, use, value added taxes, and other taxes levied in connection with Account Holder's use of WREGIS, other than taxes based on the income of WECC.

(9) Late Fees

Account Holder acknowledges that late payment of any Fees owed to WECC may cause WECC to incur extra administrative and other costs and expenses. If Account Holder fails to pay any amounts or charges that Account Holder is obligated to pay under the terms of the Agreement within fifteen days of the due date, then Account Holder shall be responsible to pay to WECC a late fee equal to one and one-half percent (monthly interest rate) computed on the overdue amount. Account Holder reserves the right to dispute the amount of the Volumetric Fee charges for a period of 90 days following payment by Account Holder. Acceptance of any late fee shall not constitute a waiver of Account Holder's default with respect to such late payment, nor prevent WECC from exercising any other rights or remedies available to WECC under the Agreement or applicable law.

(10) Term and Termination

a. **Term.** This Agreement becomes operative on the date on which Account Holder has (1) completed and submitted to the WREGIS Director Account Holder Registration Data (on-line after obtaining temporary status to use WREGIS as a Registrant), (2) indicated on the WREGIS Website Account Holder's unqualified acceptance of this Agreement, (3) paid all Fees due under this Agreement and Operating Rules, and (4) submitted to the WREGIS Director a signed copy of this Agreement. This Agreement shall continue in effect until one of the Parties terminates this Agreement pursuant to the terms of this Section 10 (Term and Termination), or the Agreement expires or terminates by operation of law pursuant to the terms of this Section.

b. **Termination for Default.** If WECC finds Account Holder in default in the performance of any of its obligations under Section 21 (Default; Remedies; Nonwaiver of Default) of this Agreement, WECC may terminate this Agreement, including Account Holder's access to WREGIS, upon giving 15 days written and electronic notice to Account Holder and an opportunity to cure in accordance with Section 21(a) hereof, unless otherwise provided herein.

c. **Termination for Convenience by Either Party.** Either Party to this Agreement may terminate this Agreement and Account Holder's access to WREGIS, without cause, by providing at least 60 days written notice to the other Party. Account Holder's obligation to pay any and all Fees due to WECC shall survive the termination of such use or access.

d. **Termination Required by Law.** WECC may terminate access to or Account Holder may cease use of WREGIS if required to do so by any statute, regulation, tariff, order, or ordinance enacted by a governmental authority having jurisdiction over Account Holder or WECC, or by any order or other decision of a court of law or governmental agency, as required by said statute, regulation, tariff, ordinance, order, or decision. At least 60 days written notice of said termination of access or cessation of use of WREGIS shall be given by the Party terminating the access to, or ceasing the use of, WREGIS under this subsection, unless a shorter notice period is required or permitted by the applicable statute, regulation, ordinance, order, or decision.

e. **Provisions that Survive Termination.** The following Sections survive termination of this agreement : Sections 7 (Fees), 10 (Term and Termination), 11 (Ownership and Uses of Data), 12 (Intellectual Property),

13 (Confidentiality), 14 (Limited Warranty; Disclaimer of Warranty), 15 (Disclaimer of Responsibility for Message Boards and Links), 16 (Limitation of Liability; Remedies), 19 (No Assignment, Transfer, or Encumbrance by Account Holder), 20 (Force Majeure), 21 (Default; Remedies; Nonwaiver of Default), 22 (Waiver), 23 (Governing Law), 24 (Dispute Resolution), 25 (Audit; Continuing Duty to Report Errors; Audit Standard), 27 (Severability), and Attachment 1 (Definitions), and any other provisions which reasonably should or must survive termination or expiration of this Agreement, or which it is reasonable to conclude that the Parties intended to survive termination or expiration of this Agreement, shall survive termination of the Agreement.

f. **Reinstatement.** WECC, at its sole discretion, may reinstate an Account Holder's access to WREGIS after the account has been terminated for Account Holder's Default, upon a determination that the problem that led to the Account Holder's termination has been satisfactorily resolved. There is no limit on the amount of time that WECC may place an Account on inactive status. If the Account Holder passed the date for his/her annual registration update while in termination, the Account Holder must update registration data before the WREGIS Director will reinstate any permission to access or use WREGIS. A new account may instead be created for this Account Holder and approved by the WREGIS Director for the Account Holder to have any permission to access or use WREGIS, at which time all forms must be resubmitted and the annual Account Holder fee must be paid.

g. **Termination due to Intellectual Property Infringement Claim.** Either Party may immediately terminate the Agreement at any time after receiving notice from a third-party alleging infringement of the third-party's intellectual property rights. Termination will be effective upon delivery by one Party of written notice to the other Party. Account Holder information that WECC has control over shall be delivered to the Account Holder as promptly as feasible.

(11) Ownership and Uses of Data

a. The Parties agree that Account Holder may directly, or through others on its behalf, report Data to WREGIS. The Parties also agree that the Account Holder will continue to own the Confidential Information reported to WREGIS by or on behalf of Account Holder. Once Data is received by WREGIS, it will be collected, stored, manipulated, and displayed in a manner unique to WREGIS. "Data" includes Static Data and Dynamic Data. "Data" does not include WREGIS software.

b. The Parties agree that WECC has the right to use and allow others to use Data reported to WREGIS as WECC reasonably deems appropriate, provided however, that Confidential Information can only be used and disclosed pursuant to the terms of this Agreement.

c. Data in WREGIS will be maintained to provide an accurate tracking database and to protect against double or multiple counting of the same Certificates. WECC has the right to retain Account Holder's Confidential Information in WREGIS even if Account Holder's account is terminated. If an Account Holder's account is terminated, WREGIS will continue to treat Account Holder's Confidential Information according to the provisions of Section 13.

(12) Intellectual Property

Copyright and/or other intellectual property laws may protect WREGIS, and any and all content of WREGIS, and any unauthorized use of the WREGIS software may violate such laws related to their protection. Except as expressly provided herein, WECC does not grant any express or implied right or license of any kind to Account Holder under any patents, copyrights, trademarks, or trade secret information with respect to WREGIS. Account Holder acknowledges that Account Holder does not acquire any ownership rights by downloading copyrighted material from WREGIS.

(13) Confidentiality

a. WECC agrees not to use or disclose Confidential Information contained in WREGIS except as authorized by this Agreement.

b. The following is deemed Confidential Information:

- Gross generation (MWhs) of each electricity Generating Unit;
- Net generation (MWhs) of each electricity Generating Unit;
- Electricity (MWhs) consumed on site by the Generating Unit owner, other than for Generating Unit use (monthly);
- Street address of the Generating Unit;
- If aggregate metering of Generating Units, number and names of Generating Units on the meter;
- Capacity factor of each electricity Generating Unit;
- Total number of Certificates in Account Holder's Account and each Subaccount; and

- Those portions of communications between Account Holder and WECC regarding WREGIS that contain any of the aforementioned information that would be treated as Confidential Information.
- The amount and timing of Certificate transfers, including transfers from one Account Holder to another and transfers among the subaccounts of an Account Holder will be treated as confidential (except with respect to a third party to whom the Account Holder has granted access).

c. The following Data reported to WREGIS is considered public information and will not be treated as Confidential Information:
   - Account Holder company name, address, and all contact information;
   - Agent's company name, address, and all other contact information;
   - Generating Unit Name;
   - Facility owner name, address, and all other contact information (other than the Generating Unit street address);
   - Nameplate capacity of the Generating Unit;
   - Generating Unit type of prime mover;
   - Energy source, and/or fuel type(s) used at Generating Units;
   - For multi-fueled Generating Units, the fuels consumed each month as a percentage of the total fuel used each month for electricity production;
   - Other eligibility characteristics;
   - Date when Generating Unit went into first commercial operation;
   - Name of facility operator, address, and contact information (other than the Generating Unit street address);
   - Meter serial or identification number;
   - Revenue meter by county, province, state, country;
   - Statement of fact that Generating Unit is or is not within WECC's region;
   - Name of Balancing Authority for the Generating Unit;
   - Name of utility to which Generating Unit is physically interconnected to;
   - Statement of fact that the Generating Unit is or is not a Qualifying Facility;
   - Facility Ownership type (a range of options);
   - Statement of fact that the Generating Unit has or has not received California Supplemental Energy Payments;
   - Statement of fact that the Facility has or has not received State/Provincial public benefits funds or support;
   - Statement of fact that the Facility has or has not received Federal Tax Credits;
   - FERC Hydro licensing information including license identifier, date of last license or application pending information;
   - Statement of fact that the Generating Unit has or has not been Repowered and date if it has been Repowered;
   - State/provincial program eligibility/certifications;

- State/provincial RPS eligibilities information as may be required for one or more states/provinces;
- Statement of fact, whether the Facility is outside of United States-Defined Protected Areas indicator;
- Certified "Low-impact" information for eligibility; and
- Information on Certification or Eligibility for Voluntary or other Mandatory Programs such as Greene-e, Ecologo, and similar programs.

d. The WECC shall protect Account Holder's Confidential Information from inadvertent disclosure and from disclosure to any third party except as authorized by Account Holder or this Agreement. WECC, its employees, members, agents, and assigns will protect and maintain Confidential Information provided by Account Holder to WECC pursuant to the provisions of this Section 13, and WECC shall obtain from all its employees, members, agents, and assigns to whom such Confidential Information is provided their agreement to comply with this Agreement.

e. Confidential Information may be aggregated with other information in WREGIS and included in Public Reports as described more fully in the WREGIS Operating Rules, so long as it is sufficiently aggregated such that a third-party reviewer could not determine the actual generation produced by a Generating Unit registered with WREGIS over any specified period of time or attribute any Confidential Information to a particular Account Holder. Information in WREGIS that is considered Confidential Information that cannot be sufficiently aggregated or masked (such as Generating Unit/Facility street addresses) such that a third-party reviewer could determine the actual Generating Unit registered with WREGIS, or attribute any Confidential Information to a particular Account Holder cannot be included in public reports.

f. If WECC is requested or required, by subpoena, oral deposition, interrogatory, request for production of documents, administrative order, or other legal or regulatory process, to disclose any Confidential Information of Account Holder, the WREGIS Director shall notify the Account Holder in writing as promptly as feasible using commercially reasonable efforts so that Account Holder may, if it so chooses and at its own expense, challenge the disclosure or seek an appropriate protective order. WECC shall reasonably cooperate with Account Holder in resolving the dispute. To the extent that the WREGIS Director and WECC have complied with the preceding provisions of this Section 13, WECC shall not be deemed to have violated its confidentiality obligations under this Agreement as a result of disclosing Account Holder's Confidential Information to a third party pursuant to a subpoena, oral deposition, interrogatory, request for production of documents, administrative order, or other legal or regulatory process.

g. In addition to the confidentiality requirements as specified in this Agreement, WECC will require adherence by the WREGIS Director, the WREGIS Committee, the WECC Staff and any persons with access to such Confidential Information, to applicable confidentiality protocols designated by WECC. These documents will be available for review on WECC's website, http://www.wecc.biz/ .

h. For purposes of this Agreement, no arbitrator engaged pursuant to Section 24 of this Agreement shall be deemed a third-party so long as such person has agreed in writing to be bound by the confidentiality obligations applicable to WECC under this Agreement and the applicable rules of the American Arbitration Association (AAA).

i. The obligations of confidentiality in this Agreement shall survive its termination without limitation in duration for so long as information continues to meet the definition of Confidential Information.

(14) Limited Warranty; Disclaimer of Warranty

a. **NEITHER PARTY, EXCEPT AS OTHERWISE PROVIDED IN SECTION 25 (b), WARRANTS THAT THE DATA IN WREGIS IS ACCURATE, CORRECT, COMPLETE, OR CURRENT.**

b. **SOFTWARE PROGRAMS USED FOR WREGIS AND THE WREGIS WEBSITE ARE PROVIDED "AS IS" TO THE ACCOUNT HOLDER. WECC MAKES NO REPRESENTATIONS OR WARRANTIES, EXPRESS OR IMPLIED, WITH RESPECT TO THIS AGREEMENT OR TO THE ADEQUACY OR PERFORMANCE OF SOFTWARE PROGRAMS USED FOR WREGIS AND THE WREGIS WEBSITE; AND, EXCEPT AS SPECIFICALLY WARRANTED IN SECTION 6(b)(iv), WECC HEREBY DISCLAIMS ANY SUCH WARRANTIES, INCLUDING BUT NOT LIMITED TO WARRANTIES OF MERCHANTABILITY, NON-INFRINGEMENT, OR FITNESS FOR A PARTICULAR PURPOSE, OR ANY IMPLIED WARRANTIES ARISING FROM ANY COURSE OF DEALING, USAGE, OR TRADE PRACTICE. WECC DOES NOT WARRANT THAT THE SOFTWARE PROGRAMS IN WREGIS WILL BE ERROR FREE OR BUG FREE. However, WECC will use commercially reasonable efforts to maintain the accuracy, correctness, completeness, and currentness of the WREGIS software, in accordance with updates and other information provided by the WREGIS software vendor.**

c. WECC is not responsible for the acts or omissions of parties other than WECC who input Data into WREGIS or from whom Data is obtained for inclusion into WREGIS.

d. Account Holder is solely responsible for the protection, security, and management of usage and security of its computer network. WECC will not compensate Account Holder for damages incurred to the extent due to security violations of the security of Account Holder's computer network, nor shall Account Holder make deductions or set offs of any kind for Fees due to WECC resulting from security violations of Account Holder's computer network.

e. WECC will have no liability for any claims for intellectual property infringement, except for claims due to its own actions, but will flow down any rights it may have to indemnity that it receives by virtue of its contract with APX, Inc .

(15) Disclaimer of Responsibility for Message Boards and Links

a. WREGIS will have the capability to host message boards (Boards) on the area of the WREGIS Website open to the public. **WECC IS NOT RESPONSIBLE FOR ANY MATERIAL POSTED BY ANY PARTY OTHER THAN WECC IN ANY MESSAGE BOARD, BULLETIN BOARD, CHAT ROOM OR IN ANY OTHER FORUM AT WREGIS (TOGETHER, THE "BOARDS").** WREGIS is merely providing access to the Boards for informational purposes. The Boards are not to be used for commercial transactions. Account Holders agree that all commercial transactions involving Certificates will take place outside of WREGIS.

b. In using the Boards, the Account Holder will not post, upload, transmit, distribute, or otherwise publish on the Boards any material that is: libelous, defamatory, obscene, abusive, pornographic, threatening, or an invasion of privacy; or an infringement of intellectual property rights, including, but not limited to, copyrights and trademarks, of any person or entity; or material that is illegal in any way or advocates illegal activity; or a message posted by a user impersonating another; or personal information such as messages which identify social security numbers, account numbers, addresses, or employer references; or chain letters of any kind; or any advertisement or solicitation of funds, goods, or services. Account Holder agrees to limit the subject matter posted, uploaded, etc. to information directly related to WREGIS Certificates. WECC reserves the right to monitor and delete any postings deemed inconsistent with its policies, this Agreement or the Operating Rules. WECC also reserves the right, at its discretion, to terminate access by any user of the Boards who

violates any of the Agreement or Operating Rules. Although WECC will make reasonable efforts to monitor materials in Boards, in no event does it assume any particular obligation to do so or assume liability for failing either to monitor the Boards or to remove specific material.

c. WECC makes no claim or representation regarding, and accepts no responsibility for, the quality, content, nature, or reliability of sites accessible by hyperlink from the WREGIS Website, or sites linking to the WREGIS Website. The linked sites are not under the control of WECC and WECC is not responsible for the content of any linked site or any link contained in a linked site, or any review, changes, or updates to such sites. The inclusion of any link does not imply affiliation, endorsement, or adoption by WECC or WREGIS of any information contained therein. When leaving the WREGIS Website, Account Holder understands that WREGIS' terms and policies do not govern the accessed website, and Account Holder will review the applicable terms and policies, including privacy and data-gathering practices, of that website.

(16) Limitation of Liability; Remedies

a. **NEITHER PARTY SHALL BE LIABLE TO THE OTHER PARTY FOR DIRECT, GENERAL, SPECIAL, INDIRECT, CONSEQUENTIAL, INCIDENTAL, EXEMPLARY, PUNITIVE, OR OTHER INDIRECT DAMAGES REGARDLESS OF CAUSE.**

b. **EACH PARTY SHALL BE ENTITLED TO SEEK SPECIFIC PERFORMANCE OF THIS AGREEMENT.**

(17) Passwords

Account Holder agrees to assume sole responsibility for the security of any passwords issued by WREGIS to Account Holder for accessing WREGIS. Account Holder shall restrict and control the use, copying, and security of its username and password to WREGIS among Account Holder's employees and agents and, to the extent reasonably within its control, prevent access to WREGIS except by those permitted to have access according to this Agreement. Each Party agrees to immediately notify the other Party of any suspected unauthorized use of Account Holder's password(s), account, or any other suspected breach of security.

(18) Viruses

WECC shall take reasonable efforts to protect WREGIS from being infected by viruses, including supplying virus protection software. However, WECC assumes no responsibility, and shall not be liable for viruses that may infect Account Holder's equipment or other property on account of Account Holder's access to use of any information or the use of WREGIS.

(19) No Assignment, Transfer, or Encumbrance by Account Holder

Neither this Agreement nor any rights under this Agreement may be assigned, sublicensed, encumbered, pledged, mortgaged, or otherwise transferred by Account Holder, in whole or in part, whether voluntary, or by operation of law, without the express prior written consent of WECC, which consent shall not be unreasonably withheld.

(20) Force Majeure

Neither Party shall be deemed to have breached any provision of this Agreement, Operating Rules, Interface Control Documents, or other applicable agreements or protocols related to WREGIS as a result of any delay, failure in performance, or interruption of service resulting directly or indirectly from acts of God, network failures, acts of civil or military authorities, civil disturbances, wars, terrorism, fires, floods, riots, embargoes, transportation contingencies, fuel shortages, interruptions in third-party telecommunications, or Internet equipment or service, other catastrophes, or any other occurrences which are beyond the claiming Party's reasonable control and which, by the exercise of due diligence, the claiming Party is unable to overcome or avoid or cause to be avoided.

(21) Default; Remedies; Nonwaiver of Default

a. **Default.** The occurrence of any of the following shall be considered a "Default":

   (i) Account Holder has failed or refused to abide by the Operating Rules or the Interface Control Documents or failed or refused to perform any of its material duties or obligations under this Agreement, other than those set forth below in Sections 21(a)(ii), (a)(iii), (a)(iv), (a)(v), and (a)(vi), which default is not substantially cured within 15 days after written notice is given to Account Holder specifying such default; provided however that if the nature of Account Holder's default is such that more than 15 days are

reasonably required to cure, then such default shall be deemed to have been cured if Account Holder commences such performance within said 15 day period and thereafter diligently completes the required action within a reasonable time thereafter.

(ii) Account Holder fails to pay any of the Fees or other charges due to WREGIS within 90 days of their due date.

(iii) Account Holder, its employees, agents, or contractors alter, tamper with, intentionally damage, or destroy (1) WREGIS, the WREGIS Website, or WREGIS Software or any portion thereof, or (2) the Data, Output, or other Confidential Information of other users of WREGIS.

(iv) Account Holder uses WREGIS in any manner that, directly or indirectly, violates any law, rule, code, or regulation or aids any unlawful act or undertaking.

(v) All or substantially all of Account Holder's assets are attached or levied under execution (and Account Holder does not discharge the same within 60 days thereafter); a petition in bankruptcy, insolvency, or for reorganization or arrangement is filed by or against Account Holder (and Account Holder fails to secure a stay or discharge thereof within 60 days thereafter); Account Holder is insolvent and unable to pay its debts as they become due; Account Holder makes a general assignment for the benefit of creditors; Account Holder takes the benefit of any insolvency action or law; the appointment of a receiver or trustee in bankruptcy for Account Holder or its assets if such receivership has not been vacated or set aside within 30 days thereafter; or, dissolution or termination of existence of Account Holder if Account Holder is not a natural person.

(vi) Knowingly, intentionally, or with willful ignorance, falsifying or misrepresenting any Output or Data input into WREGIS by Account Holder as required in Section 3(c).

b. In addition to the defaults described above, the Parties agree that if Account Holder receives written notice of a violation of the performance of any particular material term or condition of this Agreement three or more times during any 12-month period, regardless of whether such violations are ultimately cured, then such conduct shall, at WECC's option, represent a separate Default.

c. **Remedies.** Upon the occurrence of any Default, the Parties shall have the following rights and remedies, in addition to those stated elsewhere in

this Agreement and those allowed by law or in equity, any one or more of which may be exercised without further notice to Defaulting Party:

(i) If any of the items enumerated in section (a) occurs, Account Holder is in default and WECC may suspend Account Holder's access to WREGIS, upon giving 15 days written and/or electronic notice to Account Holder. If there is a dispute regarding the occurrence of a default, the Parties shall follow the provisions of Section 24 (Dispute Resolution) to settle the matter. WECC, in its sole discretion, may reinstate an Account Holder's access to WREGIS after the account has been suspended for Account Holder's Default, upon a determination that the problem that led to the Account Holder's suspension has been satisfactorily resolved and payment made for all fees and late charges (sanctions) due and owing. There is no limit on the amount of time that WECC may suspend an Account. If the Account Holder passed the date for his/her Annual Registration Update while in suspension, the Account Holder must update Registration Data before all permissions will be reinstated by the WREGIS Director.

(ii) If a Party is in Default, the Party not in Default may terminate this Agreement as provided in Section 10 (Term and Termination).

(iii) Upon termination of the use of WREGIS, Account Holder shall be obligated to pay to WECC all monies due to WECC, which shall include any interest and late fees due hereunder.

d. **Nonwaiver of Default by accepting partial payment.** WECC 's receipt of less than the full amount of Fees due shall not be construed to be a waiver of default but shall be construed as a payment on account then due, nor shall any statement on Account Holder's check or any letter accompanying Account Holder's check be deemed an accord and satisfaction or a waiver of default.

(22) Waiver

No waiver of any provision, condition, requirement, Default, or breach of this Agreement will be effective unless set forth in a written instrument executed by the Party granting the waiver. Any such waiver will be effective only in the specific instance and for the specific purpose for which it is given and will not be deemed a waiver of any other provision or of the same Default or breach upon any recurrence. No failure to exercise and no delay in exercising any right (including without limitation any remedy available to a Party) under this Agreement will operate as a waiver of such right, nor will any single or partial

exercise of any right preclude any other or further exercise of that right or any other right.

(23) Governing Law

Except for any state agency or governmental entity, Account Holders that are prohibited from using any other state's laws than their own (in which case their state law without regard to its rules on conflicts of laws shall be used), or in the case of a federal government Account Holder federal law shall apply, this Agreement shall be governed by the laws of the State of Utah without regard to its rules on conflicts of laws. Unless expressly preempted by the laws of the United States of America, the Parties expressly agree that the Uniform Computer Information Transactions Act shall not apply to this Agreement.

(24) Dispute Resolution

In the event of a dispute, controversy, or claim raised or asserted by the Account Holder, the Parties shall follow the following dispute resolution procedures.

a. FIRST STEP. Account Holder and the WREGIS Director shall first attempt in good faith to resolve the dispute by informal oral and/or written discussion(s). The Account Holder shall identify the issues and the relief sought.

b. SECOND STEP. If the Parties cannot resolve the dispute at the First Step and the Account Holder wishes to further pursue the matter, then Account Holder shall set forth the dispute in a writing entitled "Notice of Dispute" and send it, together with any supporting evidence, to the WREGIS Director. The Notice of Dispute shall in good faith describe the issue(s) in the dispute, the legal authority or other basis for the Account Holder's position, the evidence that supports the Party's position, and the remedy sought. The WREGIS Director (or designee) shall review the written dispute and confer with the appropriate Account Holder, and WECC to review and consider the dispute in good faith. The WREGIS Director (or designee) shall issue to the Parties a good faith written recommended resolution of the dispute within 15 business days after receipt of the Account Holder's Notice of Dispute. If the issues or evidence are complex, the WREGIS Director may for good cause extend the time for issuance of a recommended resolution by a reasonable amount of time not to exceed 20 calendar days. If the WREGIS Director invokes such an extension, the reason for the extension shall be stated in writing and immediately provided to Account Holder. The written recommendation of the WREGIS Director (or designee) shall include a recommended

resolution of the dispute together with a good faith informal explanation of the reasons for the recommended resolution. Neither Party shall be formally bound by the recommended resolution nor by any written submissions they may make to the WREGIS Director, although such submissions may be entered into evidence at a later dispute resolution process, if any, including arbitration or litigation.

c. THIRD STEP. Should the Account Holder disagree with the WREGIS Director's recommended resolution of the dispute, Account Holder may appeal the matter in writing to the WREGIS Committee by forwarding a written "Notice of Appeal" along with the written materials previously submitted to the WREGIS Director and a copy of the WREGIS Director's written recommended resolution of the dispute. The WREGIS Committee shall consider and decide the dispute as soon as possible at the next committee meeting and issue a written decision thereon to the Account Holder.

d. FOURTH STEP. Except for any state agency or governmental entity Account Holder's for which binding arbitration of disputes is not permitted by law, should the Account Holder disagree with the WREGIS Committee's decision and wish to further pursue the dispute, Account Holder may proceed to arbitration on the terms and conditions set forth below by sending the WREGIS Committee and the WREGIS Director a written Notice of Intent to Arbitrate, as described below, specifying the dispute and the relief sought. The dispute and any related controversy or claim arising out of or relating to these Terms of Use, or the breach thereof, or any other claim or controversy between the Parties, shall then be decided by binding arbitration administered by the AAA under its Commercial Arbitration Rules and Supplementary Procedures for Online Arbitration then in effect. Judgment on the award rendered by the arbitrator may be entered in any court of competent jurisdiction. The Parties shall mutually select one arbitrator with legal expertise in intellectual property, web-based tracking systems, and/or any one area of legal expertise that is substantially involved in the dispute, within 30 days of instituting the arbitration; otherwise the AAA shall select the arbitrator. Any hearings will be held in Salt Lake City, Utah, the Parties hereby waiving any claim or defense that such venue is not convenient or proper. Neither Party may dispute the validity of this Agreement, the Operating Rules, the Interface Control Documents, and/or protocols related to WREGIS. Any request for emergency or injunctive relief may be submitted under the AAA's Optional Rules for Emergency Measures of Protection. The arbitrator shall have no authority to award punitive damages or any other damages other than specific performance, and may not in any event make any ruling, finding or award that does not conform to the terms and conditions of these Terms of Use. Unless required by law or mutually agreed in writing by the Parties, neither Party nor the

arbitrator may disclose the existence or results of any arbitration hereunder.

e. Prior to initiating arbitration or any other form of legal or equitable proceeding hereunder, the Party seeking to arbitrate or resolve an issue (Demanding Party) shall give the other Party at least 30 days written Notice of Intent to Arbitrate describing the claim with particularity and the amount of the claim as to which it intends to initiate the action together with all supporting documentation available to the Demanding Party.

f. Each Party shall be responsible for the payment of all of its defense costs associated with the resolution of said dispute whether in arbitration or before a court of law, including but not limited to any filing fees, arbitrator fees, attorney fees, and other costs incurred in such proceeding.

g. For (i) State agency or governmental entity Account Holders for which binding arbitration of dispute is not permitted by law; or (ii) Account Holders (x) who are Balancing Authorities and are Qualified Reporting Entities acting solely in the capacity of reporting Output on behalf of a Generating Unit that is not owned by the Qualified Reporting Entity (e.g. an independent system operator) and (y) whose tariffs specify a dispute resolution process which governs the dispute; the Account Holder shall send the WREGIS Committee and the WREGIS Director a written Notice of Intent for Resolution, specifying the dispute, the relief sought, and a planned alternative course of action to resolve the dispute other than the binding arbitration process specified in this Agreement.

h. The Parties agree that neither may bring a claim nor assert a cause of action against the other, in any forum or manner, more than one year after the cause of action accrued, except where the Party could not have reasonably discovered the facts giving rise to the claim within one year.

(25) Audit; Continuing Duty to Report Errors; Audit Standard

a. WECC reserves the right to audit Account Holder's relevant records to verify any information submitted by Account Holder to WECC under this Agreement. This right shall survive for a period of three years after the expiration or termination of this Agreement and Account Holder shall maintain its records in accurate, complete, and readable form for at least that period of time after expiration or termination of this Agreement.

b. The accuracy of all information provided by Account Holder to WREGIS is of the essence in this Agreement. Account Holder hereby agrees, represents, and warrants that it will use reasonable efforts to ensure that all the information it, its Agents, or its employees provides to WREGIS shall to its knowledge be true, complete, and accurate at the time the information is provided to WREGIS. Should Account Holder discover that

any information provided or that was previously provided to WREGIS is untrue, incomplete, or inaccurate, Account Holder shall immediately notify the WREGIS Director in writing of the particular untrue, incomplete, or inaccurate information and shall provide a true, accurate, and complete update of said information to the best of its ability, as soon as is practical. This shall be an ongoing obligation of Account Holder during the term of this Agreement.

(26) Order of Precedence

Any inconsistency in this Agreement, its attachments, the Operating Rules, the Interface Control Documents, and each of their respective most current effective versions, shall be resolved by giving precedence in the following order:

1. This Agreement;
2. Attachment(s) to this Agreement;
3. Operating Rules; and
4. Interface Control Documents.

(27) Severability

a. If any provisions of this Agreement, including any provision of this Agreement and its Attachments, Operating Rules, and the Interface Control Documents, is held to be unenforceable, illegal, or in violation of a tariff or legal order of a governmental agency by a court of law or governmental agency with jurisdiction over the matter, then if the essential terms and conditions of the Agreement remain valid, legal and enforceable, such provision shall be deemed severed and shall not affect the validity of the other provisions of this Agreement, including the other provisions of the Attachments, Operating Rules, and the Interface Control Documents which will at all times remain in full force and effect.

b. (i) Further, notwithstanding any other provision of this Agreement, no provision of this Agreement (including any provision of any Attachment or other agreement incorporated into this Agreement) shall operate to obligate an Account Holder which is:

(A) a Balancing Authority, and also

(B) a Qualified Reporting Entity acting solely in the capacity of reporting Output on behalf of a Generating Unit that is not owned by the Qualified Reporting Entity

to undertake any action which the Account Holder determines to be in violation of the Account Holder's tariff, or of orders imposed upon such Account Holder by the Federal Energy Regulatory Commission ("FERC") or other governing agency/entity with jurisdiction over Balancing Authority-Account Holder.

(ii) If such Account Holder reasonably believes that any portion of this Agreement might cause or is causing a violation of its tariff or orders imposed by FERC or other governing entity, then Account Holder shall deliver to the WREGIS Director written notice, signed by a senior executive (vice president, president, or person of equivalent capacity), of Account Holder's determination. This notice shall cite the relevant provisions of the Agreement and of the tariff or orders forming the basis of the notice. Upon receipt of this notice, the terms of the Agreement specified in the notice shall be immediately and temporarily suspended as they apply to this Account Holder.

(iii) If this Agreement's essential terms and conditions are thereby affected and impaired, the Parties shall meet and confer, within three business days of such notice, or as otherwise mutually agreed. At this meeting, which may be by telephone, the Parties shall make good faith efforts to identify a mutually acceptable plan to resolve the issue, so long as its essential terms and conditions may be carried out. The Parties may, for example, develop amendments to the Agreement (and/or incorporated document), or agree to a waiver of the provision (subject to Section 22 [*Waiver*] of the Agreement), explore potential amendments to the tariff, or undertake any other actions to resolve the conflict identified by the Account Holder.

(iv) In the event that the Parties are unable to reach a resolution or agree on a written plan to include action and timelines, within five business days after the date of the notice, then either Party may terminate this Agreement for convenience pursuant to Section 10 (c) [*Termination for Convenience by Either Party*] herein, except that the terminating Party may, at its option, set the termination date to be effective immediately or for any other time up to 60 days from the date of the notice of termination; and provided further that any provision suspended by the Account Holder's notice will remain suspended through to such termination.

(v) If the Parties have agreed upon a mutually acceptable written plan pursuant to (iii) above, but one Party reasonably believes that actions

specified in the plan are not being carried out as agreed, then that Party may provide written notice to the other Party. That other Party will have 15 days following the date of the notice within which to demonstrate to the reasonable satisfaction of the first Party that the plan will be carried out as agreed. If the Party serving notice (i.e. the first Party) is not reasonably satisfied within the 15 day period, then either Party may, at its option, terminate the Agreement as provided in the preceding subsection.

(28) Notices

All notices required to be in writing under this Agreement, unless otherwise provided for herein, shall be delivered in person or by first class, registered, or certified mail (postage prepaid), or by overnight courier service to the address of the Party as either Party may specify in writing. Service shall be effective on the earlier of actual receipt or the second business day after the day of mailing (via first class mail). For service of electronic notice, it shall be deemed received on the first business day after said notice was sent to the other Party's e-mail address as designated in writing by such other Party.

(29) Capitalized Terms

Any capitalized terms contained herein that are not otherwise defined herein shall have the meanings as such terms are defined in the WREGIS Operating Rules.

(30) Entire Agreement

This Agreement, including any and all exhibits attached hereto, and the Operating Rules constitute the entire agreement of the Parties and supersede any preprinted or conflicting terms in any other prior or contemporaneous oral or written agreements and any and all other communication.

IN WITNESS WHEREOF, WECC and the Account Holder have each caused this Agreement to be executed by their respective duly authorized representatives as of the date first above written.

WESTERN ELECTRICITY COORDINATING COUNCIL

By: _____ (signature)

Name: _____

Title: _____

(ACCOUNT HOLDER)

By: _____ (signature)

Name: Juan G. Villanueva

Title: Projects & Contract Administration/DBELO Manager

ATTACHMENT 1: Definitions

a. **Account Holder**: A WREGIS Account Holder is a party that has registered with WREGIS and has established an Account within WREGIS.

b. **Active Certificates**: An active WREGIS certificate is a certificate that is held in a WREGIS Active Sub-account. Such certificates may be traded, transferred, exported, retired, or reserved at the discretion of the holder of the Active Sub-account or their agent.

c. **Active Sub-account**: The Active Sub-account is the holding place for all active WREGIS certificates. If the Account Holder has Generating Units associated with the account, or is the designated representative of a Generating Unit owner, its Active Sub-account will be the first point of deposit for any WREGIS certificates created that are associated with the Generating Unit ID number, unless the certificate is subject to a Forward Certificate Transfer. An Active Sub-account may be associated with one or more Generating Units.

d. **Affiliate**: An Affiliate of an entity is any entity that: (1) is (a) a subsidiary of such entity or (b) any partnership, limited liability company or joint venture or other form of entity which acts commercially in which such entity or any subsidiary thereof is directly or indirectly a partner, member, or venturer; or (2) directly or indirectly controls, is controlled by, or is under common control with such entity, including any limited partnership of which such other entity or any Affiliate thereof is the general partner. For purposes of this Agreement, a ten percent or greater ownership interest shall be deemed to constitute a rebuttable presumption of "control." An entity controlled by or operating as a unit, agency, or subdivision of a local, state, or provincial government or the federal government shall not be considered an Affiliate of any other entity controlled by or operating as a unit, agency, or subdivision of the local, state, or provincial government, or a federal government.

e. **Agent**: An entity outside of the Account Holder's organization that has been authorized by the Account Holder to act on its behalf within WREGIS.

f. **Assignment of Registration Rights**: The process by which the owner of a Generating Unit can assign the right to register that Generating Unit in WREGIS to another entity.

g. **Balancing Authority**: The area operator that is responsible for matching generation and load, for maintaining scheduled interchange with other balancing authority areas, and for maintaining the frequency, in real-time, of

the electric power systems.

h. **Certificate**: The term "Certificate," as used in this document, refers to a WREGIS Certificate. A WREGIS Certificate represents all of the renewable and environmental attributes from one MWh of electricity generation from a renewable energy Generating Unit registered with the WREGIS tracking system or a certificate imported from a Compatible Certificate Tracking System that has been converted to a WREGIS Certificate. WREGIS will create exactly one Certificate per MWh of generation that occurs from a Registered Generating Unit or that is imported from a Compatible Certificate Tracking System. Disaggregation of Certificates is not currently allowed within WREGIS.

i. **Compatible Certificate Tracking System (Compatible Registry and Tracking System)**: A Compatible Certificate Tracking System is a generation tracking system that has an operating agreement with WREGIS regarding the Conversion and transfer of certificates between tracking systems pursuant to a protocol developed between the WREGIS Director and the Director of the other tracking system for converting certificates from another tracking system into WREGIS certificates.

j. **Confidential Information.** Information treated as Confidential Information is listed in Section 13. B. Confidential Information does not include information which can be established by written documentation (1) to have been publicly known prior to submittal to WECC; (2) to have become publicly known, without the fault of WECC, subsequent to submittal to WECC; (3) to have been received by WECC at any time from a source other than Account Holder, so long as with respect to information submitted by a third party WECC has no reason to believe that the third party (a) is not lawfully in possession of the information or (b) is in violation of any contractual, legal, or fiduciary obligation to Account Holder with respect to the information; (4) to have been independently developed by employees or agents of WECC without access to or use of such information disclosed by Account Holder or their agents to WECC; (5) is common technical information; and (6) to have been submitted to WECC by the Account Holder for purposes other than those relating to this Agreement and not otherwise protected by a confidentiality obligation.

k. **Conversion**: A process by which certificates from a Compatible Certificate Tracking System are made available for import into WREGIS. The process involves designating the certificate as exported from the Compatible Certificate Tracking System according to the protocol agreed upon jointly by the Director of the Compatible Certificate Tracking System and the WREGIS Director. After such designation is made, the WREGIS Director will issue a corresponding WREGIS Certificate that can be used within WREGIS.

l. **Customer-Sited Distributed Generation**: Distributed generation is a parallel or stand-alone electric Generating Unit generally located in or close to a load center or customer's site (near the point of consumption) and on the customer's side of the meter. The generation produced by the distributed generation Generating Unit is used to provide electricity to the customer for a portion of its load. For WREGIS purposes, these are typically smaller installations such as those located on residential premises.

m. **Data:** Data means all recorded information, including Output and Confidential Information, regardless of form or the media on which it may be recorded that is submitted to WECC and WREGIS pursuant to this Agreement.

n. **Dynamic Data**: Dynamic Data is variable information that is associated with a specific MWh from a registered Generating Unit, such as Certificate serial number or date of generation.

o. **Export Sub-account**: The Export Sub-account is the Account Holder's designated sub-account for Certificates that have been exported out of WREGIS to a Compatible Certificate Tracking System. WREGIS Account Holders may have multiple Export Sub-accounts corresponding to the various compatible tracking systems to which exports are made.

p. **Forward Certificate Transfer**: Normally, the first point of deposit for WREGIS Certificates is the account to which a Generating Unit is associated. With a Forward Certificate Transfer, the Account Holder to which the Generating Unit is registered requests that the Certificates be directly deposited into one of their own Export, Retirement, or Reserve Subaccounts or into another WREGIS Account Holder's Active Subaccount when the Certificates are created. As a result, the first point of deposit for Certificates subject to a Forward Certificate Transfer is their other specified sub-account or the specified Active Sub-account of another Account Holder. After this initial deposit, Certificates subject to Forward Certificate Transfers shall be treated like any other Certificate for all purposes.

q. **Generating Unit**: Any combination of physically connected generators, reactors, boilers, combustion turbines, and other prime movers operated together to produce electric power. When a single facility is electrically interconnected to the utility utilizing a single meter, but represents multiple Generating Units of the same renewable generating technology and fuel type, such facility may be registered and reported as a single Generating Unit within WREGIS.

r. **Generator Owner**: The persons or legal entity that owns Generating Unit(s).

s. **Interface Control Document (ICD)**: An Interface Control Document contains the protocol for collecting and transferring data from other computer systems to the WREGIS application for the purposes of integrating data between the two systems in question. The Interface Control Document identifies the data formats, guidelines and processes that must be met in order for the data to be effectively transferred and accepted. Examples of Interface Control Documents that will be used in WREGIS are the Qualified Reporting Entity ICD (found in Appendix D of the Operating Rules), State, Provincial and Voluntary Program ICD (found in Appendix C of the Operating Rules) and the WECC Billing System ICD.

t. **Output.** Output shall mean reported renewable generation data from a Registered Generating Unit contained in standardized data files delivered to WREGIS by Qualified Reporting Entities, or by Account Holders, or by designated reporting entities using protocols described in an Interface Control Document, or a Self-Reporting Interface.

u. **Person**: A person includes any natural person, firm, association, organization, partnership, corporation, limited liability company, district, province, county, city and state, and any of the agencies and political subdivisions thereof.

v. **Qualified Reporting Entity**: An organization providing renewable Output on a unit-specific basis for the purpose of creating WREGIS Certificates that has met the Qualified Reporting Entity Guidelines established in the WREGIS Operating Rules and agreed to in the ICD.

w. **Registered Generating Unit**: A Generating Unit that has registered its facility with the WREGIS Director

x. **Registration**: The act of filling out the forms, providing required documents and paying Fees necessary to establish an Account or register a Generating Unit in WREGIS. Such forms may be obtained from the WREGIS Director.

y. **Renewables Portfolio Standard (RPS)**: Generally, a Renewables Portfolio Standard is a legislative or administrative requirement on electrical utilities, wholesale markets, or load-serving entities in a jurisdiction to include a designated percentage of renewable electricity in their generation/retail portfolio.

z. **Retirement Sub-account**: A Retirement Sub-account is used as a repository for WREGIS Certificates that the Account Holder wants to designate as retired and remove from circulation. Once a Certificate has been transferred into a WREGIS Retirement Sub-account, it cannot be transferred again to any other account or Subaccount.

aa. Retirement of Certificates: Retirement of Certificates is an action taken to remove a Certificate from circulation within WREGIS. The WREGIS Account Holder may initiate retirement for Certificates in its own account(s) or the WREGIS Director can forcibly retire any Active Certificates for cause. Retirement is effectuated by transferring Certificates into a Retirement Sub-account.

bb. Self-Reporting Interface: A Generating Unit Self-Reporting input screen within the WREGIS application which allows Self-Reporting Generating Units to manually enter their Generating Unit output. The protocol for entering data via Self-Reporting Interface will be documented in the Interface Control Document for Reporting Entities (Appendix D of the Operating Rules).

cc. Standing Order Transfer: A recurring, automatic transfer of WREGIS certificates from an Account Holder's Active Sub-account to one of their other sub-accounts, or to an Active Sub-account held by a different Account Holder.

dd. Static Data: Static data is distinct from Dynamic Data and describes the attributes of the Generating Unit that do not change based on actual operation. Static information is entered at Registration and generally includes information related to the characteristics of the generation facility such as technology type, ownership or location. See Appendix B-1 and B-2 of the Operating Rules for a list of WREGIS Static Data Fields.

ee. WECC: The Western Electricity Coordinating Council (WECC) is a regional forum for coordinating and promoting regional electric service reliability in Western Canada and the Western United States. Its service territory extends from Canada to Mexico including the provinces of Alberta and British Columbia, the northern portion of Baja California, Mexico, and all or portions of the 14 western states in between. The States that are fully included in WECC are: Washington, Oregon, California, Nevada, Idaho, Utah, New Mexico, Arizona, Colorado, Wyoming, and Montana. Texas, South Dakota, and Nebraska are partially included within WECC. A map of WECC can be found at http://www.wecc.biz/documents/constant/nerc_int.pdf. All references in the Agreement to WECC as a "Party" to this Agreement shall also be deemed to apply to any duly-selected successor in interest to WECC, if any.

ff. WECC Staff: The WECC Staff means those employees of WECC, including personnel hired by WECC or on behalf of WREGIS on a contractual basis, designated as responsible for the administration of WREGIS.

gg. Western Interconnection: The interconnected electrical systems that encompass the region of the Western Electricity Coordinating Council of the North American Electric Reliability Council. The region extends from Canada to Mexico. It includes the provinces of Alberta and British Columbia, the northern portion of Baja California (Mexico), and all or portions of the 14 western states in between.

hh. WREGIS Director: The WREGIS Director is the individual hired by WECC with the authority to oversee the administration and implementation of WREGIS, and its Operating Rules and Interface Control Document on behalf of WECC.

ii. WREGIS Software: Certain software comprising part of WREGIS, including related source code, interface, and software applications but not hardware.

jj. WREGIS Website: The related collection of web pages and interfaces associated with WREGIS that is accessible via the Internet.

(TO BE COMPLETED BY LOAD SERVING ENTITIES)
REPORT TO THE CALIFORNIA ENERGY COMMISSION
WREGIS State/Provincial/Voluntary Compliance Report and WREGIS e-Tag Summary Report
ATTESTATION FORM

Reporting Year Covered in this Report	
Title(s) of WREGIS Compliance Report(s) and WREGIS e-Tag Summary Report(s) as applicable	2013

I am an authorized officer or agent of the Load Serving Entity, as noted below, and am authorized to submit or have submitted the WREGIS State/Provincial/Voluntary Compliance Report (WREGIS Compliance Report) and associated WREGIS NERC e-Tag Summary Report (WREGIS e-Tag Summary Report) for said entity to the California Energy Commission and to attest to the following on behalf of said entity:

1) I am an authorized officer or agent of the Load Serving Entity, as noted below, and have authorized WREGIS to submit the WREGIS Compliance Report and any associated WREGIS e-Tag Summary Report for said entity to the California Energy Commission;

2) The information and data provided in the Load Serving Entity's WREGIS Compliance Report and any associated WREGIS e-Tag Summary Report is submitted to the California Energy Commission for use to verify the Load Serving Entity's procurement claims of electricity products from RPS-certified electrical generation facilities for purposes of the RPS and in accordance with the Energy Commission's *Renewables Portfolio Standard Eligibility Guidebook*;

3) I have reviewed the Load Serving Entity's WREGIS Compliance Report and any associated WREGIS e-Tag Summary Report, and to the best of my knowledge, none of the procurement claims identified in the WREGIS Compliance Report or any associated WREGIS e-Tag Summary Report, nor any of the Renewable Energy Certificates, as defined in the *Renewables Portfolio Standard Eligibility Guidebook*, associated with the electricity generation for such procurement claims, have been or will be used more than once to satisfy RPS procurement requirements or voluntary contributions;

4) I have read the *Renewables Portfolio Standard Eligibility Guidebook* and understand the provisions, eligibility criteria, and requirements of the guidebook and my responsibilities under the guidebook, including my responsibilities to provide additional information for RPS verification purposes if requested by the Energy Commission.

5) I declare under penalty of perjury that the information provided in this attestation and in the Load Serving Entity's WREGIS Compliance Report and any associated WREGIS e-Tag Summary Report is true and correct to the best of my knowledge.

Signed: _____ **Dated:** 7/29/2014

Name of Officer or Agent: Juan G. Villanueva

Authorized Officer or Agent of Load Serving Entity	
Name	Juan G. Villanueva
Title	Projects & Contract Administration/DBELO Manager
Phone	(209) 946-0246
E-mail	jvillanueva@stocktonport.com
Fax	(209) 465-2442
Load Serving Entity	
Entity Name	Stockton Port District
Street Address	2201 West Washington
City, State, Zip Code	Stockton, CA 95201

Chris Kiriakou

From: Fishback, Edward [EFishback@caiso.com]
Sent: Thursday, March 31, 2011 2:15 PM
To: Emmert, Robert; 'Chris L. Kiriakou (chris_k@cornerstoneconsulting.biz)'
Cc: 'Chris L. Kiriakou (chris_k@cornerstoneconsulting.biz)'; 'Nagata, Robert'; Hailemichael, Yilma; 'Chung, William (ET)'; Esguerra, Mark; Yan, Jason; Eisenman, Eric; Duncan, Sandy
Subject: RE: Obtaining Full Capacity Deliverability Status

Bob,
I told Chris that if his solar project was connected to a PG&E substation that was not under ISO control his request for deliverability would have to be requested through PG&E and the CAISO would perform the study, this however depended on the Utility (PG&E) having deliverability identified in their Tariff. I also told Chris that if his project was directly connected to the ISO controlled grid that deliverability would be studied by the CAISO, if requested. It was, I thought understood by both Chris and myself that the Port of Stockton Sub is owned by the Port of Stockton and the Port of Stockton is not an ISO Participating Transmission Owner (TO). I discussed with Chris that the CAISO tariff is scheduled to be revised to incorporate Non Participating TO's ability to request/obtain Full Capacity Deliverability Status, see my original e-mail sent Wednesday, March 30, 2011 11:19 AM.

My best guess is what you have highlighted below was misunderstood.

Ed Fishback
California ISO
250 Outcropping Way
Folsom, CA 95630
phone 916-608-5836
cell 916-802- 6401
fax 916-351-2264

From: Emmert, Robert
Sent: Thursday, March 31, 2011 1:06 PM
To: Fishback, Edward
Subject: RE: Obtaining Full Capacity Deliverability Status

So you agree that you did not lead them to believe what is stated in yellow below.

Bob Emmert
California ISO
916-351-2253
REmmert@caiso.com

From: Fishback, Edward
Sent: Thursday, March 31, 2011 12:01 PM
To: Emmert, Robert
Subject: Re: Obtaining Full Capacity Deliverability Status

Bob,
This project wants to interconnect into the port of stockton not a PGaE sub. Chris will have to wait for our revised tariff or interconnect via a PGaE owned distribution or ISO controlled substation.

Ed

From: Emmert, Robert
Sent: Thursday, March 31, 2011 10:29 AM
To: Fishback, Edward
Subject: FW: Obtaining Full Capacity Deliverability Status

Ed:

Please read the email below (highlights are mine). I read your email that started this chain, but it does not state what is highlighted below. Did you verbally say anything like what Sandy is stating below?

Bob Emmert
California ISO
916-351-2253
REmmert@caiso.com

From: Yan, Jason [mailto:JAY2@pge.com]
Sent: Thursday, March 31, 2011 10:23 AM
To: Emmert, Robert
Subject: FW: Obtaining Full Capacity Deliverability Status

From: Duncan, Sandra (ET)
Sent: Thursday, March 31, 2011 10:00 AM
To: Yan, Jason; Eisenman, Eric
Cc: 'EFishback@caiso.com'; Nagata, Robert; Hailemichael, Yilma (ET); Chung, William (ET); Esguerra, P Mark
Subject: FW: Obtaining Full Capacity Deliverability Status

Jason and Eric,

Ed Fishback from the CAISO told Chris Kriakou, consultant for Stockton Solar Project and Stockton IA with PG&E, that if PG&E includes the Solar Project in their in their cluster studies to be submitted to the CAISO, the CAISO will study this renewable project for deliverability assessment.

Chris is calling me asking why PG&E will not submit this project. Ed Fishback is saying that it is up to PG&E to submit this project as a Participating TO then the CAISO can include the Solar Project in the cluster deliverability assessment.

PG&E is looking like the road block in this situation to our customer. Chris has the $10,000 and wants to have a conference call with the Solar generator owner, and PG&E this afternoon around 3 pm.

thanks,

Sandy Duncan

From: Chris Kiriakou [mailto:chris_k@cornerstoneconsulting.biz]
Sent: Thursday, March 31, 2011 9:37 AM
To: Duncan, Sandra (ET)
Subject: FW: Obtaining Full Capacity Deliverability Status

Sandy,
Here is the section.

CK

From: Fishback, Edward [mailto:EFishback@caiso.com]
Sent: Wednesday, March 30, 2011 11:19 AM
To: 'Chris L. Kiriakou (chris_k@cornerstoneconsulting.biz)'
Subject: Obtaining Full Capacity Deliverability Status

Chris,
Please note below section 8.3 of the existing ISO Tariff Appendix Y GIP For Interconnection Requests. This tariff is scheduled to be revised to incorporate Non Participating TO's ability to request/obtain Full Capacity Deliverability Status.

> **8.3** To the extent that a Participating TO's tariff provides the option for customers taking interconnection service under the Participating TO's tariff to obtain Full Capacity Deliverability Status, the ISO will, in coordination with the applicable Participating TO, perform the necessary deliverability studies to determine the deliverability of customers electing such option. The CAISO shall execute any necessary agreements for reimbursement of study costs it incurs and to assure cost attribution for any Network Upgrades relating to any deliverability status conferred to such customers under the Participating TO's tariff.

Ed Fishback
California ISO
250 Outcropping Way
Folsom, CA 95630
phone 916-608-5836
cell 916-802- 6401
fax 916-351-2264

Chris Kiriakou

From: Richard Zahner [rzahner1@mac.com]
Sent: Thursday, June 23, 2011 11:45 AM
To: Jason Yan
Cc: Tom Glymph; Chris Kiriakou
Subject: Rough & Ready Solar - A 20MW PV Project

Good Morning Jason

Sandra Duncan of Transmission Contracts was kind enough to send your contact information to me and suggested I contact you regarding the 20MW Rough & Ready Solar (RRS) project at the Port of Stockton. I would like to participate in the CAISO tariff or discussions on including the RRS project in the current cluster studies.

The project has achieved site control, full zoning, and CEQA approval and is ready to build when we have a PPA. We started negotiations for a Power Purchase Agreement and found the Availability Assessment was an important step in the process of wheeling power over Port distribution system to the ISO grid.

Please let me know how Next Energy Concepts (NEC) can participate in the process.

Regards

Richard Zahner

Richard R. Zahner
Principal
Next Energy Concepts LLC (NEC)
PO Box 20245
San Jose CA 95160
408-717-0462
rzahner1@nextenergyconcepts.com

Chris Kiriakou

From: Joven, John [JRJJ@pge.com]
Sent: Monday, August 1, 2011 5:55 PM
To: 'chris_k@cornerstoneconsulting.biz'
Cc: 'Richard Smith'
Subject: RE: Rough & Ready Solar

Chris,

Sorry I have not. I've just followed up again, and I apologize for the inconvenience. To be honest, PG&E had to direct 110% of our resources to CAISO cluster projects, and this one was put on hold.

I'll see what I can do.....

Thanks,
John

From: Chris Kiriakou [mailto:chris_k@cornerstoneconsulting.biz]
Sent: Monday, August 01, 2011 5:27 PM
To: Joven, John
Cc: 'Richard Smith'
Subject: Rough & Ready Solar

John,
Did you get to a resolution of the DTT scheme questions for the Port of Stockton?
Thanks
Chris K

Chris L. Kiriakou
Cornerstone Consulting, Inc.
1565 East Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
Cell (209) 988-2294

Chris Kiriakou

From: Richard Zahner [rzahner1@mac.com]
Sent: Friday, November 4, 2011 4:57 PM
To: chris_k@cornerstoneconsulting.biz
Cc: Tom Glymph
Subject: Re: Generator Interconnection Procedures Cluster 1 and 2 Deliverability Concerns Discussion Paper

Chris

Thank you - The next RPS RFO is in the 2nd qtr 2012 and that is the likely next opportunity to bid the Rough & ready Solar into the system. I will review the ISO paper fro a better understanding of our chances.

Rich Z

On Nov 4, 2011, at 4:26 PM, Chris Kiriakou wrote:

Richard,
Attached is information regarding the CAISO status on the Deliverability Study Tariff revision issues.
Chris K

From: CAISO Communications [mailto:marketnotices@caisocommunications.com]
Sent: Wednesday, November 02, 2011 1:56 PM
To: chris_k@cornerstoneconsulting.biz
Subject: Generator Interconnection Procedures Cluster 1 and 2 Deliverability Concerns Discussion Paper

Market Notice

November 2, 2011

Categories
Grid Operation
Legal/ Regulatory
Market Operations

Requested Client Action
Request for Comment

Generator Interconnection Procedures Cluster 1 and 2 Deliverability Concerns Discussion Paper

Summary

The California ISO has posted a draft discussion paper to provide additional information on deliverability concerns identified in the Generator Interconnection Procedures cluster 1 and 2 phase 2 study.

Main Text

The ISO has posted a draft discussion paper that provides additional information related to the Generator Interconnection Procedures cluster 1 and 2 phase 2 studies to assist stakeholders in making assessments about the deliverability of their projects.

Network upgrades were identified for certain generator interconnection projects due to the high volume of generation included in the cluster 1 and 2 phase 2 studies. A number of stakeholders have raised concerns that the long development timelines and high costs of upgrades in adjacent participating transmission owner service territories will impede the commercial viability of generation projects.

The ISO is therefore providing stakeholders with engineering estimates of the amount of new generation that could achieve full capacity deliverability status without requiring certain identified high-cost and long construction-time network upgrades.

The Draft Discussion Paper - Cluster 1 and 2 Deliverability Concerns is available on the ISO website at:http://www.caiso.com/planning/Pages/GeneratorInterconnection/Default.aspx, under the Reports and studies heading. Stakeholders can submit comments on the usefulness of this information to regionaltransmission@caiso.com by close of business November 9, 2011.

For More Information Contact

Dana Young at dyoung@caiso.com

The California ISO strives to be a world-class electric transmission organization built around a globally recognized and inspired team providing cost-effective and reliable service, well-balanced energy market mechanisms, and high-quality information for the benefit of our customers.

250 Outcropping Way, Folsom, CA 95630

P&CS/ComPR/IPS/ds

Rough & Ready Solar Meeting Minutes

March 31, 2011
1:00 P.M.

Port of Stockton Commission Room

Attendees:

Port of Stockton	HCS Engineering	Solar Power Partners	Stockton Energy Center
Steve Escobar	Richard Smith	Hugh Kuhn	Tom Glymph
Jeff Kaspar		Joe Parlett	Richard Zahner
Juan Villanueva			
Cornerstone Consulting			
Chris Kiriakou			

Meeting commenced at 1:00 P.M. in the Port of Stockton Commission Room.

Chris stated that according to CalSO staff the ISO is not going to include RRS in the cluster study. PG&E is providing energy to the Port under PG&E's TO tariff but is not providing RRS with interconnection service. It was agreed that attorney involvement at this point was undesirable.

An email was received by Chris stating that Bob Emerick from Cal ISO requested that PG&E not submit RRS Project deliverability assessment because the ISO tariff does not address non-participating TO's ability to request full capacity deliverability status. The email further explained that the ISO could not provide full capacity deliverability status to a non-participating TO until the ISO tariff is modified to include non-participating TO's. Richard Zahner explained that William Cheung, head of interconnect office at PG&E, was willing to work with RRS to modify the tariff thereby enabling RRS to submit. He also estimated that most likely the proposed new tariff would be in place by August, 2011 with a new analysis beginning in March, 2012.

Chris was informed by and ISO metering representative that there must be an ISO certified meter installed at each inverter. Chris also mentioned that today is the PG&E application deadline to be included in the cluster study. RRS will need to submit a response to the PG&E RFO in order to most likely get a rejection and then decide how to move forward. Richard Zahner noted that his needs for maintenance and operations would not surpass those required by the ISO and Joe Parlett agreed that SPP would need to do its own billing. Richard Smith added that the metering section of the SIFS would probably undergo major revisions.

With regard to the lease, Richard Zahner stated that the long-term lease will detail all of SPP's obligations and commitments rather than documenting it in the SIFS. Chris requested to Richard Smith that Section 4A, Incremental Distribution Modification, be left in

the document. Richard Zahner explained to Joe that SPP Section 4 would now become Section 4A with anything added from Richard Smith relevant to current design and assumptions. Richard Zahner and Chris both agreed that the next step would be to publish a final SIFS document.

Section D of the application was populated as follows:

- In-service date November 31
- Trial operation December 1
- Commercial operation December 31, for 20 years
- Approximate interconnection point at 12 North Hooper
- Data will be collected and delivered over Port's 12kv system and delivered to PG&E
- Zero standby load when generation facility is offline
- Project name should read "SPP Rough and Ready Solar," no ampersand

Sandy Duncan, Contract Manager for PG&E, was able to call in to the meeting to respond to the group's questions. Sandy noted that PG&E has a contract with the Port but not with the project, therefore the project could not receive the deliverability assessment. She explained that PG&E could not submit the project's deliverability assessment because PG&E contracts with the Port for interconnection services, not the Project; this would violate the TO tariff. PG&E does not currently have a policy that guides a non-direct connect to the ISO.

Chris asked Sandy what the end result might be if the Port submitted an application today to be included in the 2011 cluster study. Sandy responded that PG&E would not submit it to the ISO because PG&E was already instructed not to. Sandy explained that PG&E and ISO must abide by the tariff. Chris countered that the Port provides distribution level services and the interconnection to the project while the transmission level is arranged with PG&E that is governed by the TO tariff. Sandy replied that because the project is not on the contract it would violate the tariff. However, Sandy also stated that it wasn't clear if the Port submitted the application. She will be seeking legal advice.

The group was in agreement that the application should be submitted to PG&E today.

Meeting adjourned at 3:06 p.m.

Chris Kiriakou

From: Duncan, Sandra (ET) [SMD2@pge.com]
Sent: Tuesday, March 29, 2011 10:31 AM
To: chris_k@cornerstoneconsulting.biz
Subject: RE: DEliverability

Importance: High

Chris,

You will not need $10,000 because generators that are not direct connects to the CAISO Grid cannot participate in a Deliverability Assessment Study. The CAISO Tariff does not allow for deliverability studies for generators that **indirectly** connect to the CAISO Grid. The CAISO Tariff is in the process of being updated to allow for Deliverability Assessments for generators that are **not direct connects** to the CAISO Grid; optimistically this should be available by December of 2011, maybe?

So what does Stockton do in the mean time without a Deliverability Assessment. Tell the PG&E person that you are dealing with for the RFO that you can't get a deliverability assessment because you are not a direct connect to the CAISO Grid and the CAISO Tariff doesn't allow for this. Your RFO person at PG&E should know this and if he doesn't, he can contact Jason Yan in PG&E directly for education. This means the Stockton Solar Generator will receive a slightly lower amount of money for the generation under contract because your generator cannot participate in resource adequacy during peak periods, you will not be paid for capacity until the CAISO can perform a deliverability assessment.

Definitions -

System Impact Study - PG&E does this study and the study checks for reliability constraints (direct facilities and network facilities).

Deliverability Assessment - CAISO does this study. PG&E may collect the money and send it and the application to the CAISO but the CAISO does the study as a cluster. The CAISO looks at resource adequacy to deliver all the generation during peak periods. This study is necessary to receive capacity payment under contract from RFO.

Sandy Duncan

From: Chris Kiriakou [mailto:chris_k@cornerstoneconsulting.biz]
Sent: Monday, March 28, 2011 5:55 PM
To: Duncan, Sandra (ET)
Subject: DEliverability

Sandy
See attached.
CK

Chris L. Kiriakou
Cornerstone Consulting, Inc.
1565 East Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
Cell (209) 988-2294

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Rough & Ready Solar LLC (RRS) 12/29/17

To: Jeff Kaspar

Cc: Juan Villanueva, Steve Escobar, and Chris Kiriakou, Joe Parlett

From: Richard Zahner

Date: April 15 2011

Subject: Rough & Ready Solar - Alternatives

Ref: Preliminary Financial Analysis

Jeff

The Rough & Ready Solar team has completed the preliminary financial analysis for the project and, based on the development work to date, has concluded that a straightforward 15 to 20MW roof mounted solar PV system will not be competitive in the California renewable power market.

We would like to discuss alternatives to the current roof mounted concept.

The work we have accomplished together since last July has been professional, appropriate and useful. I want to thank you and the Port Staff for your support and excellent work completing the CEQA approval process, the SIFS for the Port's electrical interconnect and coordinating the PG&E System Impact Study. We have defined a workable project for the Port and our investors.

Despite the good work on design and permitting we have been unsuccessful in securing a Power Purchase Agreement that will allow us to finance the installation. RRS made proposals to the Marin Energy Authority, The Southern California Public Power Agency, Northern California Power Authority, submitted a bid to PG&E and engaged a power marketer Evolution Markets. The result of this work indicates that renewable power prices must be in the range of $100 to $120/MWHR to be attractive to buyers. Our estimates are, that as currently envisioned, the RRS system must be paid approximately $140/MWHR to earn an attractive return for equity investors.

In summary our fixed solar array cannot compete with ground mounted tracking arrays in this market. The ground-mounted systems will have a 15 to 25% advantage in power generation and therefore income.

The alternative we would like to discuss includes reducing the roof-mounted portion of the project to 10MW that will minimize the modification to the Port's distribution system and add 15MW of ground mounted solar collectors on land

leased from the Port. All 25MW power would be wheeled to the PG&E 60kv line at the Port's substation. Assuming an average of 6 acres per MW the additional system would need not more than 90 acres at one of the following locations listed in order starting with the lowest installation cost:

- West of Humphreys St.
- Robert's Island
- A portion of the SEC Lease site south of Gillis and West of Daggett
- A strip of land at the toe of the levee along the south perimeter of the island.

Each of these options has additional costs and permit issues but preserve the unique advantage of delivery over the port's distribution system. We would like to discuss the costs to the project of leasing property at each of these locations.

Dedicating land to a ground-mounted solar system does not permanently commit the site to that purpose. The design of the tracking solar systems allows for them to be moved when a higher value use is found for the property. The project will be financed with 20yrs debt and the land can be returned to other uses at that time

Assuming that you will entertain a ground-mounted alternative, we look forward to reviewing the work to date and leasing property for that alternative.

Richard Zahner

Chris Kiriakou

From: Duncan, Sandra (ET) [SMD2@pge.com]
Sent: Tuesday, March 29, 2011 10:31 AM
To: chris_k@cornerstoneconsulting.biz
Subject: RE: DEliverability

Importance: High

Chris,

You will not need $10,000 because generators that are not direct connects to the CAISO Grid cannot participate in a Deliverability Assessment Study. The CAISO Tariff does not allow for deliverability studies for generators that **indirectly** connect to the CAISO Grid. The CAISO Tariff is in the process of being updated to allow for Deliverability Assessments for generators that are **not direct connects** to the CAISO Grid; optimistically this should be available by December of 2011, maybe?

So what does Stockton do in the mean time without a Deliverability Assessment. Tell the PG&E person that you are dealing with for the RFO that you can't get a deliverability assessment because you are not a direct connect to the CAISO Grid and the CAISO Tariff doesn't allow for this. Your RFO person at PG&E should know this and if he doesn't, he can contact Jason Yan in PG&E directly for education. This means the Stockton Solar Generator will receive a slightly lower amount of money for the generation under contract because your generator cannot participate in resource adequacy during peak periods, you will not be paid for capacity until the CAISO can perform a deliverability assessment.

Definitions -

System Impact Study - PG&E does this study and the study checks for reliability constraints (direct facilities and network facilities).

Deliverability Assessment - CAISO does this study. PG&E may collect the money and send it and the application to the CAISO but the CAISO does the study as a cluster. The CAISO looks at resource adequacy to deliver all the generation during peak periods. This study is necessary to receive capacity payment under contract from RFO.

Sandy Duncan

From: Chris Kiriakou [mailto:chris_k@cornerstoneconsulting.biz]
Sent: Monday, March 28, 2011 5:55 PM
To: Duncan, Sandra (ET)
Subject: DEliverability

Sandy
See attached.
CK

Chris L. Kiriakou
Cornerstone Consulting, Inc.
1565 East Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
Cell (209) 988-2294

subject to civil action and/or criminal penalties. If you received this transmission in error, please notify the sender by reply e-mail or by telephone (209) 634-8105 and delete the transmission.

Rough & Ready Solar LLC (RRS) 12/29/17

To: Jeff Kaspar

Cc: Juan Villanueva, Steve Escobar, and Chris Kiriakou, Joe Parlett

From: Richard Zahner

Date: April 15 2011

Subject: Rough & Ready Solar - Alternatives

Ref: Preliminary Financial Analysis

Jeff

The Rough & Ready Solar team has completed the preliminary financial analysis for the project and, based on the development work to date, has concluded that a straightforward 15 to 20MW roof mounted solar PV system will not be competitive in the California renewable power market.

We would like to discuss alternatives to the current roof mounted concept.

The work we have accomplished together since last July has been professional, appropriate and useful. I want to thank you and the Port Staff for your support and excellent work completing the CEQA approval process, the SIFS for the Port's electrical interconnect and coordinating the PG&E System Impact Study. We have defined a workable project for the Port and our investors.

Despite the good work on design and permitting we have been unsuccessful in securing a Power Purchase Agreement that will allow us to finance the installation. RRS made proposals to the Marin Energy Authority, The Southern California Public Power Agency, Northern California Power Authority, submitted a bid to PG&E and engaged a power marketer Evolution Markets. The result of this work indicates that renewable power prices must be in the range of $100 to $120/MWHR to be attractive to buyers. Our estimates are, that as currently envisioned, the RRS system must be paid approximately $140/MWHR to earn an attractive return for equity investors.

In summary our fixed solar array cannot compete with ground mounted tracking arrays in this market. The ground-mounted systems will have a 15 to 25% advantage in power generation and therefore income.

The alternative we would like to discuss includes reducing the roof-mounted portion of the project to 10MW that will minimize the modification to the Port's distribution system and add 15MW of ground mounted solar collectors on land

leased from the Port. All 25MW power would be wheeled to the PG&E 60kv line at the Port's substation. Assuming an average of 6 acres per MW the additional system would need not more than 90 acres at one of the following locations listed in order starting with the lowest installation cost:

- West of Humphreys St.
- Robert's Island
- A portion of the SEC Lease site south of Gillis and West of Daggett
- A strip of land at the toe of the levee along the south perimeter of the island.

Each of these options has additional costs and permit issues but preserve the unique advantage of delivery over the port's distribution system. We would like to discuss the costs to the project of leasing property at each of these locations.

Dedicating land to a ground-mounted solar system does not permanently commit the site to that purpose. The design of the tracking solar systems allows for them to be moved when a higher value use is found for the property. The project will be financed with 20yrs debt and the land can be returned to other uses at that time

Assuming that you will entertain a ground-mounted alternative, we look forward to reviewing the work to date and leasing property for that alternative.

Richard Zahner

Chris Kiriakou

From: Richard Zahner [rzahner1@mac.com]
Sent: Sunday, July 24, 2011 5:16 PM
To: Escobar, Steve
Cc: tglymph@nextenergyconcepts.com; chris_k@cornerstoneconsulting.biz; Villanueva, Juan
Subject: Re: Solar Request Ignites Debate - Roberts Island Solar Options

Steve

I suggest we put this in the agenda for our meeting on August 2nd and ask the Director to join us.

The dedication of agricultural land to solar power production is an important issue that I believe has not been adequately addressed by proponents of the solar power business. This is a useful discussion and it is appropriate for the County Planning Commission to set policy for all similar projects. Unlike residential and commercial developments however, a solar array can be dismantled and the land more easily returned to agriculture.

We have had discussions with the County and determined that the Port's Roberts Island parcels need not be rezoned for the installation of a solar array. We will need 'Site Approval' and we have been no reason to believe that the permit will not be granted when we make the application. The County's General plan was not sited as a reason this could not be done and we believe from our discussions of last month that the land is not covered by the Williamson Act. The Roberts Island Solar (RIS) project plan is to secure rights to the property through the Lease, complete a preliminary design using the most appropriate technology and then make the 'Site Approval' application to the County's Community Development Department at about the same time we start the CEQA process. We will have better information to describe the installation and the consequences for the land that RIS occupies.

We should also discuss the results of the latest PG&E Solar PPA solicitation - Selections for 50MW of solar PV were made last week. The prices they are offering, all under $108/MWHR, will make it very difficult for projects such as the one described in the article, to be financed. The General Plan issue may be academic for any project that does not have the advantages such as the Port's electrical distribution system. We will also be prepared to discuss the future of the Rough & Ready Solar project next week.

Regards

Richard Zahner

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"Meanwhile, **PG&E** had withdrawn and resubmitted the **Abengoa**contract – a 250 MW CSP deal that originated in the 2007 RFO. The contract is being revised for COD (now 2014), transmission, and potentially price (?) and other aspects. The IE supports the contract's viability claims (based on developer experience and milestones to-date) but notes that the pricing is still on the high-end, i.e. above 2009 MPR and comparable bids.

And yesterday, **PG&E** filed 3 deals from its Solar PV-only program. The contracts are with **Sharp/Recurrent**, **Fotowatio**, and **Westlands Solar Farms**, all begin in 2013, and are all *below the applicable (2013) MPR of $108.98."*

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Richard, please read the story from the attached link. The Director has a number of questions/concerns before signing the Roberts Island Solar lease and sharing with the
Board.

http://www.recordnet.com/apps/pbcs.dll/article?AID=/20110716/A_NEWS/107160329/-1/A_NEWS13

Thanks

Steve Escobar
Port of Stockton
Deputy Port Director, Real Estate & Port Development
2201 W. Washington Street
P.O. Box 2089
Stockton, CA 95201
T.209-946-0246
F.209-463-2362

Richard R. Zahner
Principal
Next Energy Concepts LLC (NEC)
PO Box 20245
San Jose CA 95160
408-717-0462
rzahner1@nextenergyconcepts.com

Port of Stockton
GENERATOR INTERCONNECTION REQUEST

An Interconnection Request is considered complete when it provides all applicable and correct information required below.

1. *Date:* June 15 2011

2. *Customer Information:*

Proposed Project Name: Roberts Island Solar (RIS)

Legal Name of the person or firm requesting interconnection: Next Energy Concepts LLC

Contact Person: Richard Zahner, Manager

Mailing Address: PO Box 20254

City: San Jose State: CA Zip: 95160

Telephone (Day): 408-717-0462 Telephone (Evening): Fax:

E-Mail Address: rzahner1@nextenergyconcepts.com

3. *Facility General Information:*

Proposed Facility Location on Roberts Island: A 120-acre site consisting of two parcels of approximately 60 acres each. Site location map attached.

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Application is for:
- ☒ New Generating Facility
- ☐ Capacity addition to Existing Generating Facility

If capacity addition to existing facility, please describe:

Is the Generating Facility proposed to be used for any of the following?

Net Metering?	☐ Yes	☒ No
To Supply Power to Customer?	☐ Yes	☒ No
To Supply Power to Others?	☒ Yes	☐ No

Port of Stockton
GENERATOR INTERCONNECTION REQUEST

For installations at locations with existing electric service to which the proposed Generating Facility will interconnect, provide:
Name of the Customer and Port of Stockton Account #:

Requested Point of Interconnection: A new distribution line is requested to connect the output of the Roberts Island Solar (RIS) Project to the Stockton Port District's 25MVA substation on Rough & Ready Island. The System Impact Feasibility Study (SIFS) might include connection to the adjacent WAPA 230kv transmission lines to allow delivery of the RIS output to WAPA.

Requested Interconnection In-Service Date: November 2013

- Enclose copy of site electrical one-line diagram showing the configuration of Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer.

  Is One-Line Diagram Enclosed? ☐ Yes ☒ No
  Electrical concept drawing in development

- Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address):

  The protective equipment will be both at the WAPA tower and the Port's own substation

- Enclose copy of any site documentation that describes and details the operation of the protection and control schemes.

  Is Available Documentation Enclosed? ☐ Yes ☒ No

- Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable).

  Are Schematic Drawings Enclosed? ☐ Yes ☒ No

4. Generating Facility Information
a. General Information

Data apply only to the Generating Facility, not the Interconnection Facilities.

Energy Source:
- ☒ Solar
- ☐ Wind
- ☐ Hydro
- ☐ Hydro Type (e.g. Run-of-River):
- ☐ Other (state type):
- ☐ Diesel
- ☐ Natural Gas
- ☐ Fuel Oil

Port of Stockton
GENERATOR INTERCONNECTION REQUEST

Prime Mover:
- ☐ Fuel Cell
- ☐ Gas Turbine
- ☐ Microturbine
- ☐ Other
- ☐ Reciprocating Engine
- ☐ Steam Turbine
- ☒ PV

Type of Generator: ☐ Synchronous ☐ Induction ☒ Inverter

Generator Nameplate Rating: 25,000 kW (Typical)

Generator Nameplate kVAR:

Interconnection Customer or Customer-Site Load: **500**kW (if none, so state)

Typical Reactive Load (if known):

Maximum export out of Port of Stockton electric system capability requested: 25,000kW

List components of the Small Generating Facility equipment package that are currently certified:

	Equipment Type	Certifying Entity
1.		
2.		
3.		
4.		
5.		

Is the prime mover compatible with the certified protective relay package?
☐ Yes ☐ No

Generator (or solar collector) Manufacturer, Model Name & Number:
Version Number:

☐ Single phase ☐ Three phase

Nameplate Output Power Rating in kW: Summer Winter

Nameplate Output Power Rating in kVA: Summer Winter

Individual Generator Power Factor
Rated Power Factor: Leading: Lagging:

Inverter Manufacturer, Model Name & Number (if used):

List of adjustable set points for the protective equipment or software:

Note: Additional studies will be required after the submission of this Interconnection Request.

b. Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: ☐ Instantaneous ☐ RMS

Harmonics Characteristics:

Start-up requirements:

c. Generating Facility Characteristic Data (for rotating machines)

RPM Frequency:

(*) Neutral Grounding Resistor (If Applicable):

d. Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: P.U.
Direct Axis Transient Reactance, X'_d: P.U.
Direct Axis Subtransient Reactance, X''_d: P.U.
Negative Sequence Reactance, X_2: P.U.
Zero Sequence Reactance, X_0: P.U.
KVA Base:
Field Volts:
Field Amperes:

e. Induction Generators:

Motoring Power (kW):
I_2^2t or K (Heating Time Constant):
Rotor Resistance, Rr:
Stator Resistance, Rs:
Stator Reactance, Xs:
Rotor Reactance, Xr:
Magnetizing Reactance, Xm:
Short Circuit Reactance, Xd":
Exciting Current:
Temperature Rise:
Frame Size:
Design Letter:

Reactive Power Required In Vars (No Load):
Reactive Power Required In Vars (Full Load):
Total Rotating Inertia, H: Per Unit on kVA Base

f. Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

5. Interconnection Facilities Information

a. Transformer Information

Will a transformer be used between the generator and the point of common coupling?

☐ Yes ☒ No

Will the transformer be provided by the Customer?

☐ Yes ☒ No

b. Transformer Data (If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ☐ Single Phase ☒ Three Phase Size: kVA

Transformer Impedance: % on kVA Base

If Three Phase:

Transformer Primary:	Volts	Delta	Wye	Wye Grounded
Transformer Secondary:	Volts	Delta	Wye	Wye Grounded
Transformer Tertiary:	Volts	Delta	Wye	Wye Grounded

c. Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: Type:

Size: Speed:

d. Interconnecting Circuit Breaker (if applicable):

Manufacturer: Type:
Load Rating (Amps): Interrupting Rating (Amps): Trip Speed (Cycles):

e. Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Set Point Function	Minimum	Maximum
1.		
2.		
3.		
4.		
5.		
6.		

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
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f. Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer:
Type: Accuracy Class: Proposed Ratio Connection:

Manufacturer:
Type: Accuracy Class: Proposed Ratio Connection:

g. Potential Transformer Data (If Applicable):

Manufacturer:
Type: Accuracy Class: Proposed Ratio Connection:

Manufacturer:
Type: Accuracy Class: Proposed Ratio Connection:

6. Port of Stockton Contact Information:

Designated Contact Person:	**Juan Villanueva**
	Projects & Contract Administration
Address:	**2201 West Washington Street**
	P.O. Box 2089
	Stockton, CA 95201
Telephone Number:	**(209) 946-0246**
Fax Number:	**(209) 465-7244**
E-Mail Address:	**jvillanueva@stocktonport.com**

7. Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Customer: _____ Date:_____
(Original signature required)

Signed: Richard R Zahner, Manager Next Energy Concepts LLC

Chris Kiriakou

From: Richard Zahner [rzahner1@mac.com]
Sent: Sunday, July 24, 2011 5:16 PM
To: Escobar, Steve
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Thanks

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rzahner1@nextenergyconcepts.com

PORT OF STOCKTON

Phone: (209) 946-0246

Fax: (209) 465-7244

December 6, 2010

Director Office of Service and Sales
Pacific Gas and Electric Company
77 Beale Street, Mail Code 19C
P.O. Box 770000
San Francisco, CA 94177

Gentlemen,

Section 11.4 of the Interconnection Agreement Between the Pacific Gas & Electric Company and the Stockton Port District requires that if either party anticipates a "Significant Operational Change" that may materially affect the other party they must provide notice of such change. The Port has received a request from a project proponent to develop and construct up to a 20 MW photovoltaic generating facility on Rough & Ready Island and interconnect it with the Port's electric system. Since this amount of generation is substantial compared to the Port's load there may be an impact on the interconnection between the Port and PG&E.

The Project proponent has requested an accelerated schedule in order to meet an end of 2011 on line date for their project. Please advise us of your concerns, if any, at the earliest possible time. If you have any further questions please feel free to contact Juan Villanueva or myself at (209) 946-0246.

Sincerely,

Jeff Kaspar
Deputy Port Director Real Estate & Port Development

CC: Juan Villanueva
Chris Kiriakou

Manager, Business Customer Services
Pacific Gas and Electric Company
77 Beale Street, Mail Code 13L
P.O. Box 770000
San Francisco, CA 94177

System Impact/ Facilities Study Plan

SPP Rough & Ready Solar LLC

Study Plan

Stockton Port District
2201 West Washington Street
Stockton, CA 95203
(209) 946-0246

November 17, 2010

Table of Contents

1. Introduction and Overview

On June 29, 2010 Stockton Energy Center LLC (SEC) entered into a License Agreement with the Stockton Port District (District) in which SEC has access to the roofs of 37 warehouses on Rough & Ready Island for the purpose of installing individual solar generation systems on each of the roofs. See Figure 1 for the location of the roofs. SEC proposed the construction of a solar generating project named SPP Rough & Ready Solar LLC (RRS) and has assigned its rights under the License Agreement to the new entity. The total maximum electrical generating capacity of the project will not exceed 20 MW. RRS is in the preliminary engineering phase of the project's development.

The District proposes to perform a System Impact/Facility Study (SIFS) for interconnection of the RRS project to the District's 12 kV distribution system including impacts and requirements as a result of the District's delivery of the RRS project's electrical output to the Pacific Gas & Electric Company (PG&E) transmission system at the District's 60 kV point of interconnection. The study will also include impacts on and requirements of the Third Parties that the District has agreements with. The Third Parties are PG&E and the California Independent System Operator (CAISO).

This SIFS defines the scope, content, assumptions, and terms of reference of the SIFS.

The District operates a 12 kV electric distribution system and a 60 kV interconnection with PG&E on Rough & Ready Island. The District has specific agreements with PG&E and the CAISO that govern the physical and operational parameters of the interconnection including protection, metering and generation.

Electrically it is the District's responsibility to install and maintain equipment to provide comprehensive and coordinated protection at its interconnection point with PG&E. The installation of a 20 MW generation project on the District's electric distribution system will require that some existing and new equipment have approved additional directional protection and it will be coordinated with upstream District and PG&E equipment. This will require approval by the District and PG&E prior to interconnection of the generation. RRS will be required to balance its generation output between three phases as nearly as practicable.

The SIFS will not address momentary voltage fluctuations, or voltage flicker on the District's system. RRS is responsible for limiting the voltage flicker and voltage imbalance that their project causes to the District's system at the individual warehouse interconnection points.

2. Study Plan

The System Impact Facility Study Plan includes:

1. Project Preliminary Engineering – It will be RRS' responsibility to produce preliminary engineering drawings of their project and its proposed interconnection point with the District's distribution system including each building array supply voltage and kilowatt production. The District will then review the proposed project preliminary engineering and interconnection with the District's distribution system.

The SIFS will cover general topics including; character of power delivered (voltage, power factor, wave form), site specific general issues, District monitored generation metering, identify PG&E and CAISO issues to be addressed, communication, power accounting, reporting and other contractual issues.

2. Distribution Interconnection Requirements – An evaluation of the District's 12kV distribution system and impacts on it from an 18MW of distributed generation including line capacity and upgrade requirements, distribution protection study, transformation requirements, substation/interconnection protection study, phasing and grounding requirements, metering and communications, incremental line loss estimate, and West Complex Substation coordination. District data, communication and control system needs for RRS will need to be addressed conceptually as part of this SIFS. The SIFS will provide +/- 20% estimates of the costs associated with any the work required to interconnect RRS facilities and deliver it to the CAISO controlled grid.
3. An important part will be the determination of the impacts, if any, on the District's existing load and future load growth.
4. Third Party Agreements – The District has agreements with PG&E and the California Independent System Operator. Each of the agreements has notice requirements for any material modification to the District's system. Once the project is adequately defined those notice requirements will have to be implemented. The results of those notices and any subsequent studies will then be incorporated into the SIFS.
5. Identification of Agreement Requirements - The interconnection requirements will be included in a long-term lease agreement between the District and RRS. It is anticipated that major contract issues will be identified as part of the SIFS.
6. Exclusions: The SIFS will not address structural review and impact on the warehouse roof's to support the equipment (The structural engineering is R&RS' responsibility). The SIFS will not address RRS' internal controls and communication systems nor internal metering (if any). The SIFS will not provide detail engineering estimates or construction drawings of any system modifications, controls, or equipment upgrades.

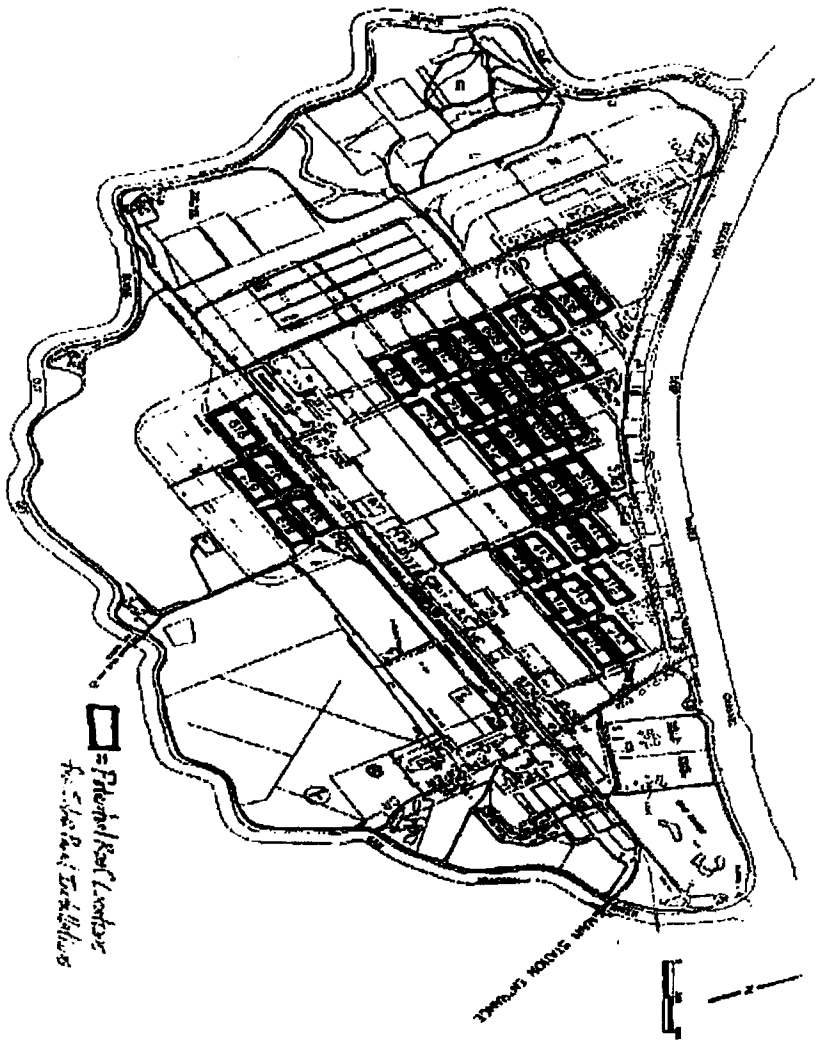

Figure 1 – Potential Roof/Project Locations.

3. Study Fee

RRS, will be required to reimburse the District for performing the required System Impact Facility Study covering work that is reasonably necessary to evaluate the impact of RRS' request for service.

The District has estimated a study fee of $25,000 for performing this SIFS based upon the scope of this Study Plan. The final cost to complete the SIFS will be based on actual cost. The District will provide RRS with a record of actual costs for performing this SIFS after the SIFS is completed.

A $10,000 deposit will be made to the District to initiate the Study. A second $15,000 payment will be made 30 days after the work begins. When the Study is finalized, the District will notify RRS of the actual cost incurred and either refund monies not spent or bill for the balance.

4. Schedule

The following schedule shows the milestones associated with the Study Plan

Task	Milestone Description	Task Time Requirement
1	Establish study commencement date based on receipt of study fee with the SIFS Study Agreement.	(Note 1)
2	Complete Preliminary Engineering Review	14 Days
3	Complete Distribution Interconnection Requirements	45 Days
4	Complete Third Party Requirements (PG&E/CAISO)	(Note 2)
5	Issue SIFS Final Report	(Note 3)

Notes:

1. Upon receipt of the study fee and an executed SIFS Study Plan the District will commence Tasks listed above. Response to District Data Requests to RRS may impact the Task Timing.
2. Third party review will be dependent upon their determination of time required. Additional costs associated with third party review will be the responsibility of RRS.
3. Issuance of the SIFS Final Report will be dependent upon the provision of information by RRS, completion of any third party review and other factors related to this study that may impact the performance of the Study Plan.

5. Project Information

The District will perform a SIFS based on the preliminary project information. At the completion of the review of the preliminary engineering a request for additional detailed information concerning the project will be provided to RRS. To the extent there are changes in the project's design, there may be additional review required by the District or third parties.

6. Interconnection Assumptions

With input from RRS, the District will conduct the SIFS using the following assumptions:

1. The output of the project will be at unity power factor. (RRS to provide this information)

2. The SIFS will not address momentary voltage fluctuations, or voltage flicker on the District's system. RRS is responsible for limiting the voltage flicker and voltage imbalance that the project causes to the District's system.

3. The project output is phased balanced as nearly as practicable. The power inverter system shall be line side interactive and have the potential to stop generating power if the distribution system goes off-line due to external events.

4. Normal load growth on the District's distribution system and known specific load increases at the time of study initiation will be included in the study.

5. Available Transmission, Substation, and Distribution capacity for this study is based on normal load projections. Unforeseen load increases by other District customers made subsequent to the RRS' request may reduce available transmission, substation, and distribution capacity and may require additional upgrades not included in this SIFS and not attributable to RRS. Third party requirements and terms will be identified during Task 4 of the SIFS.

6. RRS will provide phase and ground protection at the interconnection point with the District's distribution system in accordance with the District's requirements. Changes to the RRS settings on the protective equipment shall be coordinated and approved by the District.

7. The project boundaries will be at the delivery side of the individual building solar array meter. RRS will be responsible for solar collector array, collections boxes, and inverters. The District will provide all equipment to transform the output to 12kv and deliver that power to the nearest 12.5kv line by the least reasonable and practicable cost method available.

8. A subsequent detailed Facility Engineering and Construction Study will provide the details of the interconnection, modifications to the substation, reinforcement to the distribution line facilities and metering and control systems.

7. Study Scope

7.1 Distribution Feeder / Substation Load & Voltage Studies

Based on the generation information provided by RRS and system load projections used by the District, substation, distribution feeder, and equipment load from 2011 to 2015 will be studied. Voltage conditions on the distribution feeders serving RRS and other affected feeders will be studied. Corrective actions and associated costs as a result of the project generation addition will be identified.

7.2 Distribution Feeder Protection Studies

Short Circuit studies will be conducted to determine the fault duties on existing District facilities and proposed project interconnection points.

7.3 Distribution Line Evaluation

Based on the District's internal studies, the District will identify any pre-existing overload or voltage problems consistent with sections 7 and 8. The distribution line evaluation will determine the scope and cost required to provide service to the new multiple interconnection points to the District's distribution system via the interconnection plan. It will also determine the incremental losses associated with the wheeling of RRS' 20 MWs of distributed generation to the District's point of interconnection with the CAISO controlled grid.

7.4 Substation Evaluation

The Substation evaluation will:

1) Determine new equipment, if any, needed to accommodate the new generation including the associated costs.

2) Identify any existing equipment, if any, requiring upgrades to mitigate problems caused by overload or overstress and identify what the proposed mitigation action will be including the associated costs.

7.5 Third Party Evaluation and Requirements

The Third Party Evaluation will:

1) Determine new equipment, if any, needed to accommodate the new generation.

2) Identify any existing equipment, if any, requiring upgrades to mitigate problems caused by overload or overstress and identify what the proposed mitigation will be and its costs.

3) Determine the impacts and requirements of Under Frequency Load Shedding and manual load shedding as required by the CAISO.

8. General Criteria for Identifying Overloads

Normal overloads are those that exceed 100% of normal summer ratings. Emergency overloads are those that exceed 100% of emergency summer ratings. In the event of a CAISO system wide power crisis, the District is required to initiate Under Frequency Load Shedding and manual load shedding.

9. General Criteria for Identifying Voltage Problems

Distribution feeder studies of the normal conditions will be performed for the summer 2011 through 2015 peak loads with the following assumptions:

- Summer 2011 through 2015 Projected Peak load for the District and current circuit configuration is used.
- Voltage not meeting the regional utility service voltage limits practice, under all reasonably expected load conditions is considered to be a voltage problem that requires correction.

10. Cost Estimates

A preliminary engineering cost estimate for mitigating any system impact to the District's existing facilities that is caused solely by the interconnection of the RRS' proposed project will be provided. This cost estimate will include any modifications to the substation, and reinforcement to the distribution line facilities required to interconnect the proposed generation project. Third party requirements will be provided as received.

This estimate also will not include any facilities constructed, owned and operated by the RRS or any land, licenses and right of way costs associated with new facilities identified by the study.

All costs provided will be preliminary estimates only. Final charges to the RRS will be made based upon the actual costs incurred by the District.

Stockton Port District

System Impact Facility Study Agreement

SPP Rough & Ready Solar, LLC has reviewed the SIFS plan for its project and interconnection with the Stockton Port District's electric distribution system on Rough & Ready Island in San Joaquin County, and agrees with the proposed work scope, estimated cost, and schedule.

Dated this 22nd day of November, 2010

STOCKTON PORT DISTRICT

Jeff F. Kaspar,
Deputy Port Director Real Estate & Port Development

ROUGH & READY SOLAR, LLP

Joseph Parlett,
Project Manager

SPP Rough & Ready Solar LLC

100 Shoreline Hwy. Suite 210B
Mill Valley CA 94941
415-389-8781

PORT OF STOCKTON

Phone: (209) 946-0246

Fax: (209) 465-7244

January 3, 2013

Director, Office of Service and Sales
Pacific Gas and Electric Company
77 Beale Street, Mail Code 19C
P. O. Box 770000
San Francisco, CA 94177

Subject: Significant Operational Change

Dear Mr. Metague,

Pursuant to section 11.2 of the Interconnection Agreement Between Pacific Gas and Electric Company and the Stockton Port District, the Port of Stockton is advising PG&E of the Port's decision to consider the construction of a 1.5 MW Photovoltaic Power Plant to be located on Rough & Ready Island and connected to the Port's distribution system. At this time, the plant is anticipated to become energized and commercially available at the end of 2014.

This plant is under consideration as part of the Port's utility planning to meet the State of California's Renewable Portfolio Standard. Should you have any questions please feel free to call me at (209) 946-0246.

Sincerely,

Juan G. Villanueva
Projects & Contract Administration/
DBELO Manager

cc: Steve Escobar

Manager Business Customer Services
Pacific Gas and Electric Company
77 Beale Street, Mail Code 13L
P. O. Box 770000
San Francisco, CA 94177

PORT OF STOCKTON

Phone: (209) 946-0246

Fax: (209) 465-7244

May 5, 2014

Mr. John Hubenthal, Project Development Director
RGS Energy
2955 Kerner Blvd.
San Rafael, CA 94901

Dear Mr. Hubenthal,

Thank you for preparing your April 7, 2014 updated proposal for a 1 or 2 MW fixed or tracking solar photovoltaic generating plant. As you know the Port has been reviewing the options for meeting the State of California's Renewable Portfolio Standard (RPS). Until just recently we were considering the construction of a 1.5 MW fixed PV plant. The Port had just successfully completed a System Interconnect Study with PG&E to identify any technical issues that a plant located on Rough & Ready Island would have. Having found no significant issues the Port was in the process of identifying the lowest cost construction option.

As part of our due diligence we also surveyed the market for any potential options that would meet our immediate needs. It was during this due diligence review that an opportunity to purchase renewable power through the use of the Category 1 Renewable Energy Certificates (RECs) was identified. Category 1 RECs are tired directly to a specific renewable resource that is either in California or whose power is delivered to the California bulk transmission system without any modification to its generation schedule or power delivery. Because of market conditions this offer of Category 1 RECs presented a significantly lower cost to the Port to meet its RPS requirements. This opportunity caused us to reconsider a purchase of RPS supply from the market.

At this time the Port has determined that, for the immediate future, it will pursue the purchase of Category 1 RECs and associated power to meet its RPS needs. Although there are some issues to be determined we believe this will be the most effective and economic way for the Port to meet its RPS obligation. Also at this time, the Port will not be pursuing the construction of an onsite renewable generating plant. I would like to emphasize that our potential purchase of RECs is not a long term purchase and the Port will continue to review the opportunities available to it that have economic and regulatory value.

If you have any questions or would like to discuss this further please feel free to call me or Chris Kiriakou. Again, thank you for your proposal and sharing your company's experience and significant capabilities.

Sincerely,

For

Steve Escobar,
Deputy Port Director, Real Estate and Port Development

CC: Gary W. Woody
Juan G. Villanueva
Chris Kiriakou

1565 E. Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
chris_k@cornerstoneconsulting.biz

CORNERSTONE CONSULTING

Memo

To: Steve Escobar

From: Chris Kiriakou

CC: Juan Villanueva

Date: May 5, 2014

Re: April 7, 2014 RGS Solar PV Proposal

On April 7, 2014 the Port received a proposal from RGS Energy/Bockmon & Woody to construct a 1 to 2 MW solar photovoltaic plant on Rough & Ready Island. The proposal provided four options; 1 or 2 MWs and fixed or tracking panels. Following is a summary of the proposal and a review of opportunities available to the Port from the California power market.

The proposal provides for the construction of a Renewable Portfolio Standard (RPS) qualifying plant that enables the Port to meet its state requirements to provide renewable energy to its retail load. A summary from the proposal is included in the following Table 1.

	1 MW Option		2 MW Option	
	Fixed Tilt	**Tracker**	**Fixed Tilt**	**Tracker**
Wstc,system	1,008,330	1,008,330	2,016,660	2,016,660
System Price	2,515,030	2,898,949	$4,937,340	$5,568,732
$/W (standard conditions)	$2.49	$2.88	$2.45	$2.76
Modual Count	3,306	3,306	6,612	6,612
Watts/mod	305	305	305	305
Pfactor, kWhac/kWhdc	1,654	2,041	1,654	2,041
kWh/y1	1,667,778	2,058,002	3,335,556	4,116,003

Table 1. System Summary (From Proposal, Page 3)

The levelized cost of the various plant options are summarized in Appendix 2 Financial analysis, Summary – Levelized PPA rate and annual production.

	Fixed Tilt	Tracker
1 MW	14.67 cents/kWh	13.67 cents/kWh
2 MW	14.06 cents/kWh	12.96 cents/kWh

Table 2. Levelized Costs (From Proposal Appendix 2)

Levelized costs in this analysis are the economic equivalent rate for the duration of the 20 year Purchase Power Agreement analysis period assuming a 5% cost of money. Insufficient detail was provided to verify the numbers. In addition, the 20 year O&M costs identified on page 4 of the proposal is $470,682, or approximately and average of $0.0057/kWh. Assuming the best rate for the 2 MW tracker system and ignoring its O&M costs we have a comparison rate for the following market alternative.

Power Supply Cost Element	Cost/kWh
Power (2015 On-Peak Block Energy)	$0.05200
CAISO Transmission (2013)	$0.01422
CAISO Ancillary Services (2013 Ave. Cost)	$0.00406
Resource Adequacy (2015 local RA and Eq. Energy)[1]	$0.02332
Category 1 REC (2015)	$0.01900
Total Cost of Market Alternative	**$0.10854**

Table 3. Cost of RPS Market Alternative

The total cost of the market alternative includes all costs associated with the delivery of power over the CAISO controlled grid and the associated charges. It also assumes that CAISO Resource Adequacy Cost can be offset by the capacity of the plant and spread over the equivalent energy output. This may not be totally achievable due to the recent inclusion of a CAISO Flexible Capacity Cost for system reliability needs associated with renewable resources. Given this best case for the proposed PV plant the cost is still 19.4% higher than the market alternative.

Future market price risks are evident in that the 2017 Shell proposal price of Category 1 RECs at $25/REC (1,000 kWhs) or $0.025/kWh, is an increase of nearly 32% over 2016. However, this is still within an acceptable range of risk as the price of RPS resources may go up or stay the same based on technological and efficiency improvements and price inflation.

Recommendation

By far the market has provided a viable no upfront cost option to the Port for meeting its RPS requirements. The nearly 20% saving with no upfront cost, no ongoing maintenance costs, and a simplified power supply arrangement through the use of Shell as the Port's Scheduling Coordinator makes the use of Category 1 RECs attractive. It is recommended that the Port accept the Shell proposal for the sale of Category 1 RECs to the Port for 2015 through 2017. It is also recommended that the Port send the attached letter to RGS Energy/Bockmon & Woody advising them of the Port decision.

[1] At this time the Port has not requested capacity deliverability analysis from the CASIO for capacity use. In this analysis it is assumed that the PV plant capacity can be used to offset Resource Adequacy capacity requirements as the base case. It is added as a cost to the market purchase to provide comparability.

Draft RGS Energy /Bockmon & Woody Letter

May 5, 2014

Mr. John Hubenthal, Project Development Director
RGS Energy
2955 Kerner Blvd.
San Rafael, CA 94901

Dear Mr. Hubenthal,

Thank you for preparing your April 7, 2014 updated proposal for a 1 or 2 MW fixed or tracking solar photovoltaic generating plant. As you know the Port has been reviewing the options for meeting the State of California's Renewable Portfolio Standard (RPS). Until just recently we were considering the construction of a 1.5 MW fixed PV plant. The Port had just successfully completed a System Interconnect Study with PG&E to identify any technical issues that a plant located on Rough & Ready Island would have. Having found no significant issues the Port was in the process of identifying the lowest cost construction option.

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At this time the Port has determined that, for the immediate future, it will pursue the purchase of Category 1 RECs and associated power to meet its RPS needs. Although there are some issues to be determined we believe this will be the most effective and economic way for the Port to meet its RPS obligation. Also at this time, the Port will not be pursuing the construction of an onsite renewable generating plant. I would like to emphasize that our potential purchase of RECs is not a long term purchase and the Port will continue to review the opportunities available to it that have economic and regulatory value.

If you have any questions or would like to discuss this further please feel free to call me or Chris Kiriakou. Again, thank you for your proposal and sharing your company's experience and significant capabilities.

Sincerely,

Steve Escobar,
Deputy Port Director, Real Estate and Port Development

CC: Gary W. Woody
Juan Villanueva
Chris Kiriakou

System Impact Study Report

Generation Interconnection (Wholesale)

Port of Stockton, California

Rough & Ready Island Solar Project

Pacific Gas and Electric Company

WE DELIVER ENERGY.

January 15, 2014

Table of Contents

Appendices:

1. Executive Summary

Port of Stockton, pursuant to Section 11.2 of the Interconnection Agreement between Pacific Gas & Electric Company (PG&E) and the Stockton Port District, has submitted an interconnection request for their Rough & Ready Island Solar Project (Project).

The Project would add 2.0 MW of solar photovoltaic generation to the Port of Stockton's 12 kV distribution system, which is currently connected to PG&E's Rough & Ready 60 kV Substation. The proposed Commercial Operation Date (COD) of the Project is December 31, 2014.

This SIS Report has been updated at the customer's request for **Non-Export** interconnection at the Port of Stockton 60kV bus that is tapped off of the Rough & Ready 60kV tap line.

The SIS was conducted to determine the impacts of the Project on PG&E's electric transmission system and the results are documented in this report and the attached appendices. The SIS provides the:

- PG&E transmission system impacts caused solely by the addition of the Project;
- PG&E system reinforcements necessary to mitigate any adverse impacts of the Project under various system conditions; and
- PG&E facilities required for system reinforcements with a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct.

To determine the system impacts caused by the Project, studies were performed using the following system model base cases:

- 2015 Summer Peak and Summer Off-Peak Conditions

The studies performed included:

- Steady State Power Flow Analyses
- Reactive Power Deficiency Analyses
- System Protection Analysis

Power Flow Study Results

Steady state power flow and reactive power deficiency analyses concluded that the generation of 2.0 MW in the Port of Stockton's 12 kV distribution system does not cause any thermal overloads or reactive power deficiencies.

Details of the power flow study can be found in Appendix C.

System Protection Requirements

The detailed preliminary protection requirements can be found in Appendix D.

Cost Estimates for PG&E Preliminary Scope of Work

There are no anticipated protection impacts or work at the existing PG&E Source substations for this Non-Export interconnection.

The non-binding cost estimate for the protection submittal review is $25,000.

2. Project and Interconnection Information

Table 5-1 provides general information about the Project as provided in the interconnection request.

Table 5-1: Project General Information

Project Location	Stockton, CA
PG&E Planning Area	Stockton Division (Central Valley)
Type of Generators	Solar – Xantrex Model
Maximum Generator Output	2.0 MW
Generator Auxiliary Load	0 MW
Maximum Net Output	**Non-Export**
Power Factor	0.99
Step-up Transformer	Existing at PG&E Rough & Ready Substation
Description Of Interconnection	PG&E Rough & Ready Substation
Connection Voltage	60 kV

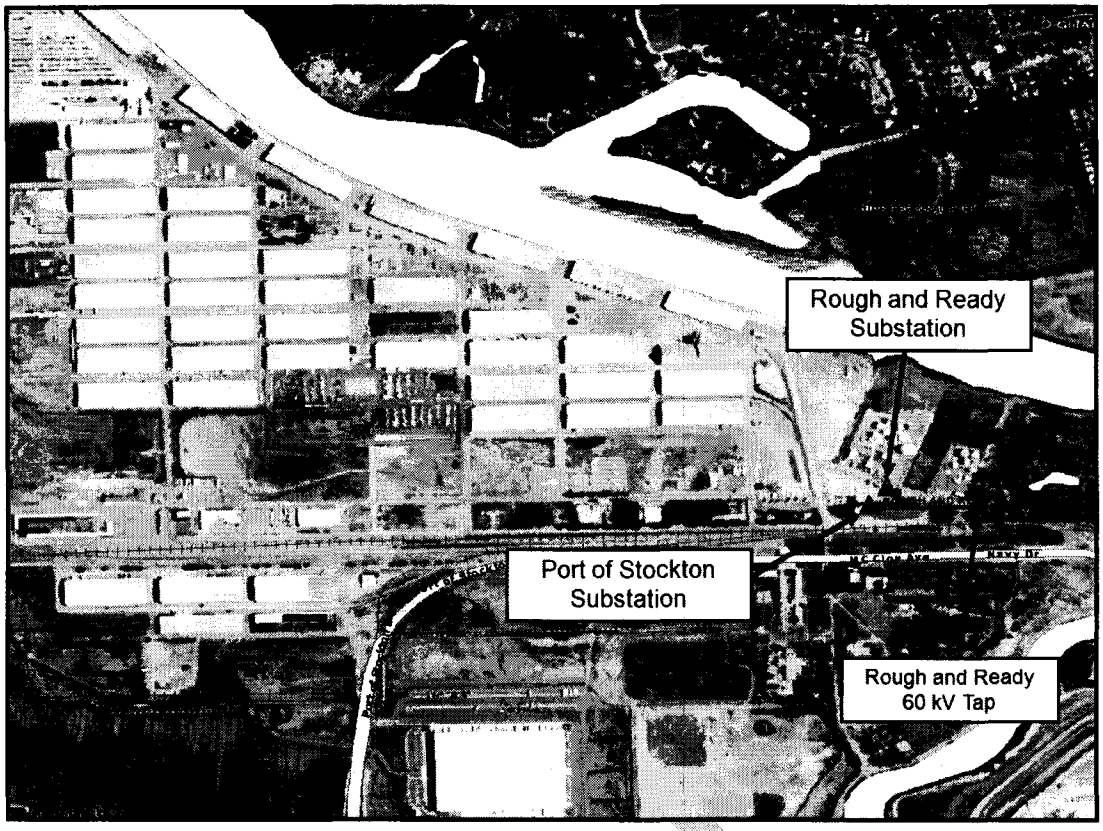

Figure 2-1 – Vicinity Map

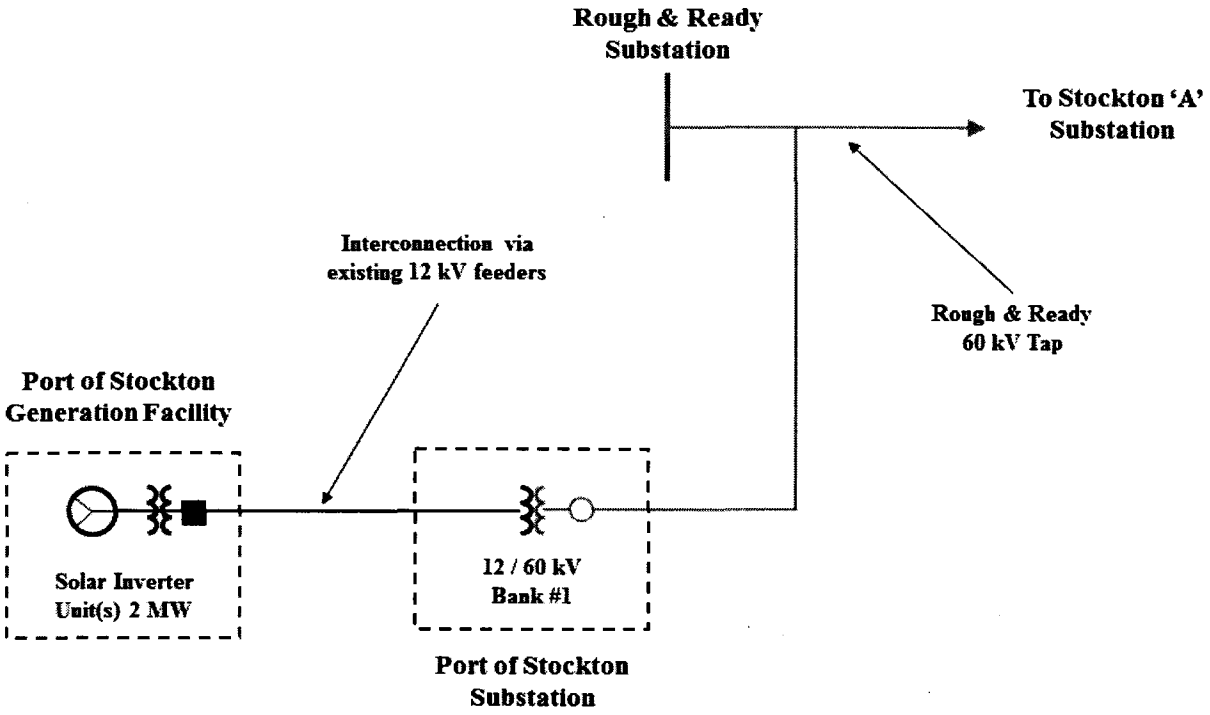

Figure 2-2 – Proposed Single Line Diagram

3. Study Assumptions

PG&E conducted the SIS under the following assumptions:

1) This project is Non-Export.

2) The expected Commercial Operation Date of the Project is December 31, 2014.

3) The Port of Stockton will engineer, procure, construct, own, operate and maintain its Project facility.

4) This study took into account all approved PG&E transmission projects and proposed generating facilities in PG&E's service territory that will be operational by December 31, 2014.

4. Power Flow Study Base Cases

Power flow analyses were performed to ensure that PG&E's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results to these power flow analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. If a NERC reliability problem exists as a result of this interconnection, it is PG&E's responsibility to identify the problem and develop an appropriate corrective action plan to comply with NERC reliability standards.

As part of PG&E's obligations with NERC as the registered Transmission Owner for the PG&E transmission system, the study results for this interconnection will be communicated to the CAISO and any other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities are solicited to ensure coordination of transmission systems.

PG&E cannot guarantee that the Project:

a) can operate at maximum rated output 24 hours a day, year round, without system impacts; nor

b) will not have system impacts during the times and seasons not studied in the SIS.

Two (2) power flow base cases were used to evaluate the transmission system impacts of the Project. While it is impossible to study all combinations of system load and generation levels during all seasons and at all times of the day, these base cases represent extreme loading and generation conditions for the study area.

- 2015 Summer Peak Full Loop Base Case:

Summer peak power flow base cases were used to evaluate the transmission system impacts of the interconnection of the Project on the PG&E system. Power flow analysis was performed using PG&E's 2015 Summer Peak Base Case (in General Electric Power Flow format). This base case is from PG&E's 2012 base case series and has a 1-in-10 year adverse weather load level for the Central Valley Area.

- 2015 Summer Off-Peak Full Loop Base Case:

Power flow analysis was also performed using PG&E's 2015 Summer Off-Peak Base Case (in General Electric Power Flow format) in order to evaluate potential congestion on transmission facilities during the Off-Peak system conditions. The loads in this base case are about 50% of the summer peak loads.

These base cases will model all the CAISO approved PG&E transmission projects that will be operational in 2014 and 2015.

5. Steady State Power Flow Study and Results

The CAISO controlled-grid Reliability Criteria, which incorporates the Western Electricity Coordinating Council (WECC) and NERC planning criteria, was used to evaluate the impact of the Project on the PG&E transmission system.

5.1 Contingencies

Power Flow analysis was performed using the base cases described in Section 4. These base case were used to simulate the impact of the Project during normal (CAISO Category "A") operating conditions as well as during single (CAISO Category "B") and selected multiple (CAISO Category "C") contingency conditions.

The types of contingencies evaluated under each category are summarized in Table 5-1. The contingencies used in this SIS are provided in Appendix B.

Table 5-1: Summary of Planning Standards

Contingencies	Description
CAISO Category "A"	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages for the transmission lines and generators within the study area.
CAISO Category "C"	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-230 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

Although most of the CAISO Category "C" contingencies have been considered to be evaluated as part of this study, it is impractical to study all the CAISO Category "C" contingencies. For this reason, select critical Category "C" contingencies (C1 – C9) were evaluated as part of this study.

5.2 Study Results

5.2.1 Normal Overloads (CAISO Category "A")

Under projected 2012 summer peak and summer off-peak conditions, the addition of the Project caused no new Category "A" normal overloads.

5.2.2 Emergency Overloads (CAISO Category "B")

Under projected 2012 summer peak and summer off-peak conditions, the addition of the Project caused no new Category "B" emergency overloads.

5.2.3 Emergency Overloads (CAISO Category "C")

Under projected 2012 summer peak and summer off-peak conditions, the addition of the Project caused no new Category "C" emergency overloads.

The power flow plots are shown in detail in Appendix C.

6. Short Circuit Analysis

Short circuit studies were performed to determine the impact of increased fault duty resulting from the proposed interconnection. The study determined the maximum fault currents on various transmission buses in the vicinity of the Project.

Table 6-1 lists the available short circuit duty at the buses electrically adjacent to the Project. This data was used to determine if any equipment would be overstressed by the interconnection of the Project.

Table 6-1: Short circuit study results

Fault Location	kV	Pre-Project		Post-Project		% Increase	
		3LG (A)	1LG (A)	3LG (A)	1LG (A)	3LG	1LG
Port of Stockton	60	6,823	5,262	6,847	5,267	0.35	0.1

All breakers at the Port of Stockton substation are not PG&E owned and have not been evaluated for the fault currents calculated above. These fault currents will not impact any of the PG&E source breakers.

7. Reactive Power Deficiency Analysis

With the proposed Project included in the system model, CAISO Category "B" and "C" contingencies were analyzed to identify any reactive power deficiency:

- Whether the results show voltage drops of 5% or more from the pre-Project levels, or
- Whether the results fail to meet applicable voltage criteria.

The power flow studies of Category "B" and "C" contingencies indicate that the Project did not cause voltage drops of 5% or more from the pre-project levels, or cause the PG&E system to fail to meet applicable voltage criteria.

8. Preliminary Protection Requirements

Per Section G2.1 of the PG&E Interconnection Handbook, PG&E protection requirements are designed and intended to protect PG&E's system only. The IC is responsible for the protection of its own system and equipment and must meet the requirements in the PG&E Interconnection Handbook.

Protection requirements may include but are not limited to direct transfer trip schemes installed at PG&E and IC facilities. The IC is responsible for installing the leased lines used for direct transfer trip communication and the necessary direct transfer trip transmitters.

These Preliminary Protection Requirements are based upon an interconnection plan

as shown in Figure 2-2. Appendix D provides more details of the preliminary protection requirements.

9. Telemetry Requirements

General telemetry requirements can be found in Section G1 of PG&E's Interconnection Handbook.

Generating Facilities of 1 MW or greater require MW and MVar telemetry for visibility.

The PG&E Interconnection Handbook is available on the PG&E web site at:

http://www.pge.com/about/rates/tariffbook/ferc/tih/

10. Environmental Evaluation/ Permitting

10.1 CPUC General Order 131-D

PG&E is subject to the jurisdiction of the California Public Utilities Commission (CPUC) and must comply with CPUC General Order 131-D (Order) on the construction, modification, alteration, or addition of all electric transmission facilities (i.e., lines, substations, switchyards, etc.). This includes facilities to be constructed by others and deeded to PG&E. In most cases where PG&E's electric facilities are under 200 kV and are part of a larger project (i.e., electric generation plant), the Order exempts PG&E from obtaining an approval from the CPUC provided its planned facilities have been included in the larger project's California Environmental Quality Act (CEQA) review, the review has included circulation with the State Clearinghouse, and the project's lead agency (i.e., California Energy Commission) finds no significant unavoidable environmental impacts. PG&E or the project developer may proceed with construction once PG&E has filed notice with the CPUC and the public on the project's exempt status, and the public has had a chance to protest PG&E's claim of exemption. If PG&E facilities are not included in the larger project's CEQA review, or if the project does not qualify for the exemption, PG&E may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Negative Declaration or Environmental Impact Report).

When PG&E's transmission lines are designed for immediate or eventual operation at 200 kV or more, the Order requires PG&E to obtain a Certificate of Public Convenience and Necessity (CPCN) from the CPUC unless one of the following exemptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built. Obtaining a CPCN can take as much as 18 months

or more if the CPUC needs to conduct its own CEQA review, while a CPCN with the environmental review already done takes only 4-6 months or less.

Regardless of the voltage of PG&E's interconnection facilities, PG&E recommends that the project proponent include those facilities in its project description and application to the lead agency performing CEQA review on the project. The lead agency must consider the environmental impacts of the interconnection electric facility, whether built by the developer with the intent to transfer ownership to PG&E or to be built and owned by PG&E directly. If the lead agency makes a finding of no significant unavoidable environmental impacts from construction of substation or under-200 kV power line facilities, PG&E may be able to file an Advice Letter with the CPUC and publish public notice of the proposed construction of the facilities. The noticing process takes about 90 days if no protests are filed, but should be done as early as possible so that a protest does not delay construction. PG&E has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, PG&E may then need to apply for a formal permit to construct the project (i.e., Permit to Construct). Facilities built under this procedure must also be designed to include consideration of electric and magnetic field (EMF) mitigation measures pursuant to PG&E "EMF Design Guidelines for New Electrical Facilities: Transmission, Substation and Distribution". For projects that are not eligible for the Advice Letter/notice process but have already undergone CEQA review, PG&E would likely be able to file a "short-form" CPCN or PTC application, which takes about 4-6 months to process.

Please see Section III, in General Order 131-D. This document can be found in the CPUC's web page at:

http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

10.2 CPUC Section 851

Because PG&E is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires PG&E to obtain CPUC approval of leases and licenses to use PG&E property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with CEQA. PG&E recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, PG&E recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

11. Technical Requirements

The PG&E Interconnection Handbook explains the technical requirements for interconnection of loads and generators to PG&E's transmission system. The Interconnection Handbook documents facility connection requirements to the PG&E

system as required in NERC Standard FAC-001-0. They are based on applicable FERC and CPUC rules and tariffs (e.g., Electric Rules 2, 21 and 22), as well as accepted industry practices and standards. In addition to providing reliability, these technical requirements are consistent with safety for PG&E workers and the public.

The PG&E Interconnection Handbook applies to Retail and Wholesale Entities, which own or operate generation, transmission, and end user facilities that are physically connected to, or desire to physically connect to PG&E's electric system. All technical requirements described or referred to in the Handbook apply to new or re-commissioned Generation Facilities. The Generation Interconnection Handbook comprising sections G-1 through G-5 applies to Generation Entities.

PG&E has established standard operating, metering and equipment protection requirements for loads and generators. The Interconnection Handbook covers such requirements for all transmission-level load and generation entities wishing to interconnect with PG&E's electric system. Additional, project-specific requirements may apply and are documented in this SIS report.

The PG&E Interconnection Handbook includes, but is not limited to such operating requirements as the following:

- The Project must be able to meet the power factor requirements of 90 percent lagging and 95 percent leading.

- The Project must have Automatic Voltage Regulation (AVR) and be able to maintain the generator voltage under steady-state conditions within ±0.5 percent of any voltage level between 95 percent and 105 percent of the rated generator voltage.

Generators must also meet all applicable CAISO, NERC, and WECC standards. NERC and WECC standards include, but are not limited to such requirements as the following:

- The Project must be able to remain on line during voltage disturbances up to the time periods and associated voltage levels as required by the WECC Low Voltage Ride Through (LVRT) standards that are in-line with FERC Order No. 161-A. The WECC LVRT standard is available on the WECC web site at:

  http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/Shared%20Documents/Voltage%20Ride%20Through%20White%20Paper.pdf

- Currently NERC is working on a Voltage Ride Through standard, PRC-024-1, that would be applicable to all generators interconnecting to the transmission grid. Until PRC-024-1 is effective, PG&E and the CAISO will require that all generators comply with the existing WECC LVRT requirements. The PRC-024-1 standard Draft 1 can be found on the NERC web site at

  http://www.nerc.com/docs/standards/sar/PRC-024-1_Draft1_2009Feb17.pdf

All generators must satisfy the requirements of the PG&E's Interconnection Handbook and meet all applicable CAISO, NERC, and WECC standards. PG&E will not agree to interconnect any new generators unless all technical and contractual requirements are met.

The IC should be aware that the information in the PG&E Interconnection Handbook is subject to change. Parties interconnecting to the PG&E electric system should verify with their PG&E representative that they have the latest versions. The PG&E Interconnection Handbook is available on the PG&E web site at:

http://www.pge.com/about/rates/tariffbook/ferc/tih/

12. Study Updates

The SIS was performed in according to the assumptions shown in the Sections titled "Study Assumptions" and "Power Flow Study Base Cases". In the event that these assumptions are changed, an updating study may be required to re-evaluate the Project's impact on the CAISO controlled-grid. The IC would be responsible for paying for any such updating study.

System Impact Study Plan

Generation Interconnection

Stockton Port District

SPP Rough and Ready Solar

DRAFT

Pacific Gas and Electric Company

WE DELIVER ENERGY.

February 4, 2011

Table of Contents

1. Introduction

The Stockton Port District, an Interconnection Customer (IC), has submitted a completed Interconnection Request (IR) to Pacific Gas and Electric Company (PG&E) for their proposed SPP Rough and Ready Solar Project (Project). The maximum net output of the Project to the California Independent System Operator (CAISO) controlled-grid will be 17 MW, with a proposed Commercial Operation Date (COD) of December 31, 2011.

The Project will install solar panels on the rooftop of IC owned property warehouses, which are connected on the 12 kV distribution feeders at the IC owned Port of Stockton 60 kV Substation. The Project will utilize the existing 12/60 kV transformer at the Port of Stockton 60 kV Substation to send generation into PG&E's transmission grid. Excluding any metering requirements, no physical equipment modifications will be made at the Port of Stockton 60 kV Substation.

The Port of Stockton 60 kV Substation is identified as a non-CAISO controlled facility. Therefore, PG&E has accepted the IC's Interconnection Request under PG&E's Transmission Owner Tariff (TO)[1]. PG&E will proceed with a System Impact Study (SIS) to determine the impact of the Project on PG&E's electric transmission system. This SIS will identify:

- Transmission system impacts caused solely by the addition of the project;
- System reinforcements necessary to mitigate any adverse impacts of the Project under various system conditions; and
- Facilities required for system reinforcements with a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct.

This SIS Study Plan will form the basis for the SIS Agreement (SISA) by defining the scope, content, assumptions, and terms of reference of this SIS.

2. Study Fee

PG&E has estimated a study fee of $25,000 for performing this SIS. The final cost to complete this SIS will be based on actual cost. PG&E will provide the IC a record of actual costs for performing this SIS roughly two months after the study is completed. PG&E will bill the IC the remaining balance if the actual cost is higher than the estimated $25,000. If the actual cost is less than the estimated study fee, PG&E will refund the balance to the IC.

[1] PG&E's study will still be required to adhere to certain CAISO interconnection criteria because the Project will be generating power into the CAISO controlled-grid.

3. Schedule

Table 3-1 shows the milestones/schedules associated with the study.

Table 3-1: Study Schedule

Task	Milestone Description	Target Date
1	PG&E receives study fee with the SISA	February 14, 2011
2	PG&E issues draft SIS report to IC	+30 BDs

The IC must execute and return the attached SISA including the estimated study fee of $25,000 by the tenth business day from the tendering of this study plan. If the IC fails to return an executed SISA with the estimated study fee within 10 business days, the Project will be removed from the interconnection queue.

4. Cost Estimates

The SIS will provide a list of required facilities with a non-binding good faith estimate of cost responsibility and a non-binding good faith estimate of time to construct facilities necessary to interconnect the Project. These costs have no associated degree of accuracy and are provided for informational purpose only.

5. Project and Interconnection Information

Table 5-1 provides general information about the Project as provided in the IR.

Table 5-1: Project General Information

Project Location	Stockton, CA
PG&E Planning Area	Stockton Division
Type of Generators	Xantrex GE 500 Solar Inverters
Maximum Generator Output	20 MW
Generator Auxiliary Load	3 MW
Maximum Net Output to Grid	17 MW
Power Factor	0.99 lagging and leading[2]
Step-up Transformer	One 12.47/60 kV, 24 MVA Transformer at 7.89% impedance on a 25 MVA base
Description Of Interconnection Configuration	Port of Stockton 60 kV Substation bus
Connection Voltage	60 kV

Figure 5-1 provides the map for the Project location.

[2] PG&E's Interconnection Handbook requires that the Project be able to meet power factor requirements of 90 percent lagging and 90 percent leading.

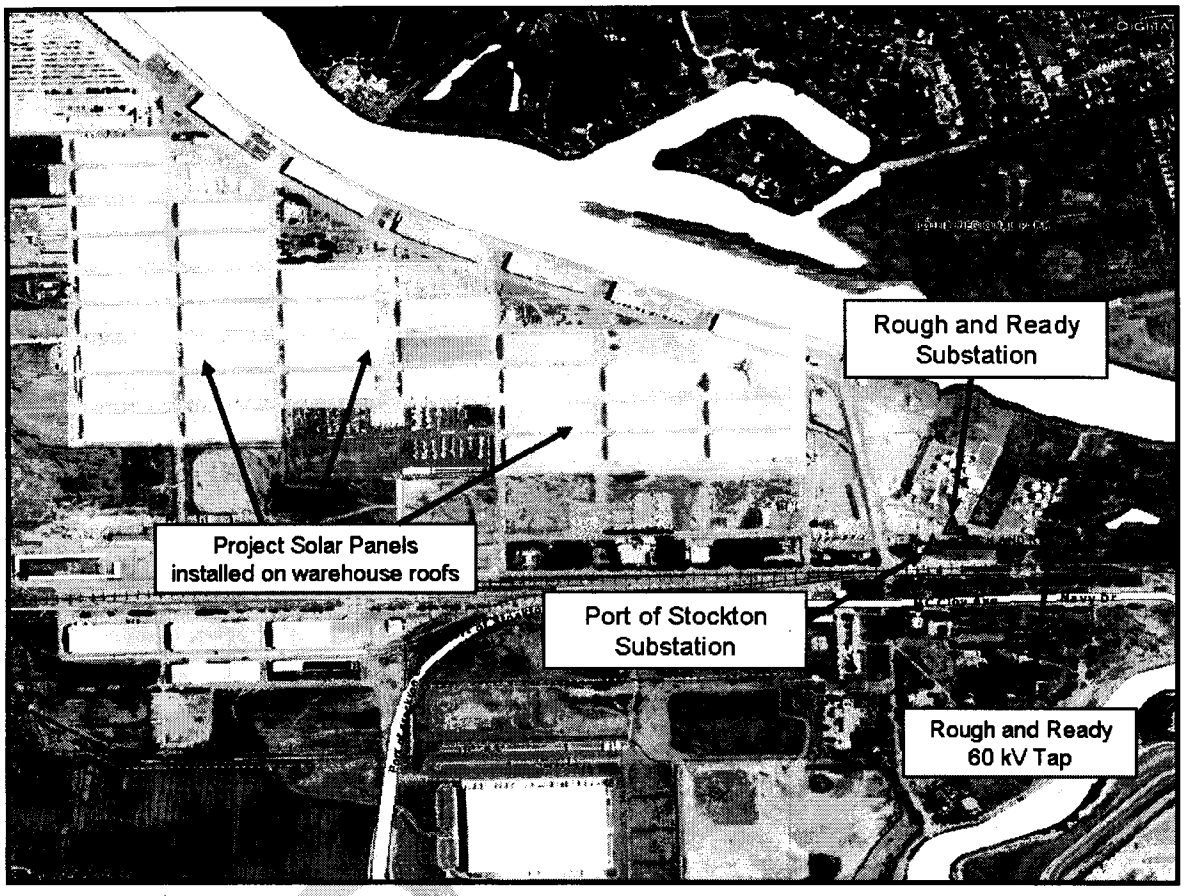

Figure 5-1: Vicinity Map

6. Study Assumptions

PG&E will conduct the SIS under the following assumptions:

1) The maximum net output of the Project to the transmission grid is 17 MW.

2) The expected Commercial Operation Date of the Project is December 31, 2011.

3) The IC will be installing solar panels on the rooftop of their existing property warehouses, which are connected on the 12 kV distribution feeders at the IC owned Port of Stockton Substation.

4) The Project will utilize the existing 12/60 kV transformer at the Port of Stockton Substation.

5) Excluding any metering requirements, no physical equipment modifications will be made at the Port of Stockton Substation.

6) The IC will engineer, procure, construct, own, operate and maintain its Project facility.

7) This study will take into account the planned generating facilities in PG&E's service territory that are ahead of this Project in PG&E's Generation Interconnection Queue. This includes CAISO, PG&E Wholesale Distribution Tariff, and Transmission Owner Tariff planned generating facilities. In addition, all CAISO approved PG&E transmission projects that will be operational by December 2011 will also be included.

7. Power Flow Study Base Cases

Power flow analyses will be performed to ensure that PG&E's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results to these power flow analyses will serve as documentation that an evaluation of the reliability impact of new facilities and their connections on interconnected transmission systems is performed. If a NERC reliability problem exists as a result of this interconnection, it is PG&E's responsibility to identify the problem and develop an appropriate corrective action plan to comply with NERC reliability standards.

As part of PG&E's obligations with NERC as the registered Transmission Owner for the PG&E transmission system, the study results for this interconnection will be communicated to the CAISO and any other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities are solicited to ensure coordination of transmission systems.

Two power flow base cases will be used to evaluate the transmission system impacts of this interconnection. While it is impractical to study all combinations of system load and generation levels during all seasons and at all times of the day, these base cases represent extreme loading and generation conditions for the study area.

The CAISO and PG&E cannot guarantee that the Project:

a) can operate at maximum rated output 24 hours a day, year round, without system impacts; nor

b) will not have system impacts during the times and seasons not studied in the SIS.

The following power flow base cases will be used for the analysis and SIS:

- 2012 Summer Peak Full Loop Base Case:

  Power flow analysis will be performed using PG&E's 2012 Summer Peak Full-Loop Base Case (in General Electric Power Flow format). This base case was developed from PG&E's 2010 base case series and has a 1-in-10 year adverse weather load level for the Stockton Division.

- 2012 Summer Off-Peak Full Loop Base Case:

  Power flow analysis will also be performed using PG&E's 2012 Summer Off-Peak Full Loop Base Case (in General Electric Power Flow format) to evaluate potential congestion on transmission facilities during the Off-Peak system condition. The Summer Off-Peak season load of approximately 50% the PG&E Summer peak load will be applied in this Summer Off-Peak Peak Base Case.

These base cases will model all CAISO approved PG&E transmission projects that would be operational by December 2011. The base cases will also model all proposed generation projects that are ahead of this project in PG&E's Generation Interconnection Queue. However, some generation projects that are electrically far from the Project will be either turned off or modeled with reduced generation to balance the loads and resources in the power flow model. The major generation projects included are shown in Attachment 1.

8. Study Scope

The SIS will determine the impact of the Project on PG&E's transmission system using CAISO Reliability Criteria. The specific studies to be conducted are outlined below:

8.1 Steady State Power Flow Analysis

The CAISO controlled-grid Reliability Criteria, which incorporates the Western Electricity Coordinating Council (WECC) and NERC planning criteria, will be used to evaluate the impact of the Project on the PG&E transmission system.

Power Flow analysis will be performed using the base cases described in Section 7. These base case will be used to simulate the impact of the Project during normal (CAISO Category "A") operating conditions as well as during single (CAISO Category "B") and selected multiple (CAISO Category "C") contingency conditions. The study will cover the transmission facilities within PG&E's North Valley Area.

The types of contingencies to be evaluated under each category are summarized below Table 8-1.

Table 8-1: Summary of Planning Standards

Contingencies	Description
CAISO Category "A"	All facilities in service – Normal Conditions
CAISO Category "B"	• B1 - All single generator outages. • B2 - All single transmission circuit outages. • B3 - All single transformer outages. • Selected overlapping single generator and transmission circuit outages for the transmission lines and generators.
CAISO Category "C"	• C1 - SLG Fault, with Normal Clearing: Bus outages (60-230 kV) • C2 - SLG Fault, with Normal Clearing: Breaker failures (excluding bus tie and sectionalizing breakers) at the same bus section above. • C3 - Combination of any two-generator/transmission line/transformer outages. • C4 - Bipolar (dc) Line • C5 - Outages of double circuit tower lines (60-230 kV) • C6 - SLG Fault, with Delayed Clearing: Generator • C7 - SLG Fault, with Delayed Clearing: Transmission Line • C8 - SLG Fault, with Delayed Clearing: Transformer • C9 - SLG Fault, with Delayed Clearing: Bus Section

Although most of the CAISO Category "C" contingencies will be considered for this study, it is impractical to evaluate all the CAISO Category "C" contingencies. For this reason, select critical Category "C" contingencies (C1 – C9) will be evaluated as part of this study.

8.2 Reactive Power Deficiency Analysis

With the generation project included in the system model, CAISO Category "B" and "C" contingencies will be analyzed to identify any reactive power deficiency:

- Whether the results show voltage drops of 5% or more from the pre-Project levels, or
- Whether the results fail to meet applicable voltage criteria.

A post-transient power flow analysis will be performed, if deemed necessary, after considering the network topology or power transfer paths involved when a significant amount of power transfer occurs.

8.3 Voltage Stability Analysis

The NERC/WECC Planning Standards requires sufficient reactive resources needed to provide reactive power support for adequate voltage support and control. The CAISO Grid Planning Standards encompasses the NERC Planning Standards and the WECC Reliability Standards. Following is the associated WECC-S1 standard.

For transfer paths, post-transient voltage stability is required with the Path modeled at a minimum of 105% of the path rating (or Operational Transfer

Capability) for system normal conditions (Category "A") and for single contingencies (Category "B"). For multiple contingencies (Category "C"), post-transient voltage stability is required with the path modeled at a minimum of 102.5% of the path rating (or Operational Transfer Capability).

8.4 Dynamic Stability Analysis

Dynamic stability studies will be conducted using the 2012 Summer Peak Full Loop Base Case to ensure that the transmission system remains in operating equilibrium, as well as operating in a coordinated fashion, through abnormal operating conditions after the new facility begins operation.

Disturbance simulations will be performed for a study period of up to 20 seconds to determine whether the new facility will create any system instability during the following outages.

8.4.1 CAISO Category "B"

- Full load rejection of 20 MW of the Project.
- A three-phase close-in fault on the Stockton 'A' #1 60 kV Line at the Port of Stockton 60 kV bus with normal clearing time followed by loss of the Stockton 'A' #1 60 kV Line.
- A three-phase close-in fault on the Stockton 'A' #1 60 kV Line at the Stockton 'A' 60 kV bus with normal clearing time followed by loss of the Stockton 'A' #1 60 kV Line.

8.4.2 CAISO Category "C"

- A three-phase fault on the Port of Stockton 60 kV bus
- A three-phase fault on the Stockton 'A' #1 60 kV bus

8.5 System Protection Analysis

Short circuit studies will be performed to determine the impact of increased fault duty resulting from the proposed interconnection. The study will determine the maximum fault currents on various transmission buses in the vicinity of the Project. Equipment that may become overstressed as a result of the added generation will be identified.

The SIS will also provide the preliminary protection requirements that are for informational purposes only. Cost estimates and work scope for the protection and automation requirements will be provided if the project progresses to the Facilities Study.

Per Section G2.1 of the PG&E Interconnection Handbook, PG&E protection requirements are designed and intended to protect PG&E's system only. Additional protection is typically needed to adequately protect the IC's facilities. The IC is responsible for the protection of its own system and

equipment and must meet the requirements in the PG&E Interconnection Handbook.

8.6 Transmission Line Evaluation

PG&E's transmission line evaluation will identify any existing equipment requiring upgrades to mitigate any adverse impacts due to the Project. Preliminary scope of work, and non-binding costs for these potential system upgrades will be included in the transmission line evaluation for the SIS.

However, the feasibility, detailed scope of work, and detailed costs for these potential system upgrades are not included in the transmission line evaluation for the SIS.

Detailed cost estimates and work scope for the transmission line evaluation will be provided if the project progresses to the Facilities Study.

8.7 Substation Evaluation

The substation evaluation will identify any existing equipment requiring upgrades to mitigate any problems caused by overstress or overload due to the Project. Preliminary scope of work, and non-binding costs for these potential system upgrades will be included in the substation evaluation for the SIS.

However, the feasibility, detailed scope of work, and detailed costs for these potential system upgrades are not included in the substation evaluation for the SIS.

Detailed cost estimates and work scope for the transmission line evaluation will be provided if the project progresses to the Facilities Study.

8.8 Land Evaluation

For the SIS, PG&E's Land Department will not perform an evaluation to determine if any new land rights are necessary to upgrade PG&E facilities that may be impacted by the Project, such as constructing the new generator tie line or reconductoring of existing PG&E transmission lines, if required.

A land rights evaluation will be provided if the Project progresses to the Facilities Study.

9. Environmental Evaluation/Permitting

9.1 CPUC General Order 131-D

PG&E is subject to the jurisdiction of the California Public Utilities Commission (CPUC) and must comply with CPUC General Order 131-D (Order) on the construction, modification, alteration, or addition of all electric transmission facilities (i.e., lines, substations, switchyards, etc.). This includes

facilities to be constructed by others and deeded to PG&E. In most cases where PG&E's electric facilities are under 200 kV and are part of a larger project (i.e., electric generation plant), the Order exempts PG&E from obtaining an approval from the CPUC provided its planned facilities have been included in the larger project's California Environmental Quality Act (CEQA) review, the review has included circulation with the State Clearinghouse, and the project's lead agency (i.e., California Energy Commission) finds no significant unavoidable environmental impacts. PG&E or the project developer may proceed with construction once PG&E has filed notice with the CPUC and the public on the project's exempt status, and the public has had a chance to protest PG&E's claim of exemption. If PG&E facilities are not included in the larger project's CEQA review, or if the project does not qualify for the exemption, PG&E may need to seek approval from the CPUC (i.e., Permit to Construct) taking as much as 18 months or more since the CPUC would need to conduct its own environmental evaluation (i.e., Negative Declaration or Environmental Impact Report).

When PG&E's transmission lines are designed for immediate or eventual operation at 200 kV or more, the Order requires PG&E to obtain a Certificate of Public Convenience and Necessity (CPCN) from the CPUC unless one of the following exemptions applies: the replacement of existing power line facilities or supporting structures with equivalent facilities or structures, the minor relocation of existing facilities, the conversion of existing overhead lines (greater than 200 kV) to underground, or the placing of new or additional conductors, insulators, or their accessories on or replacement of supporting structures already built. Obtaining a CPCN can take as much as 18 months or more if the CPUC needs to conduct its own CEQA review, while a CPCN with the environmental review already done takes only 4-6 months or less.

Regardless of the voltage of PG&E's interconnection facilities, PG&E recommends that the project proponent include those facilities in its project description and application to the lead agency performing CEQA review on the project. The lead agency must consider the environmental impacts of the interconnection electric facility, whether built by the developer with the intent to transfer ownership to PG&E or to be built and owned by PG&E directly. If the lead agency makes a finding of no significant unavoidable environmental impacts from construction of substation or under-200 kV power line facilities, PG&E may be able to file an Advice Letter with the CPUC and publish public notice of the proposed construction of the facilities. The noticing process takes about 90 days if no protests are filed, but should be done as early as possible so that a protest does not delay construction. PG&E has no control over the time it takes the CPUC to respond when issues arise. If the protest is granted, PG&E may then need to apply for a formal permit to construct the project (i.e., Permit to Construct). Facilities built under this procedure must also be designed to include consideration of electric and magnetic field (EMF) mitigation measures pursuant to PG&E "EMF Design Guidelines for New Electrical Facilities: Transmission, Substation and Distribution". For projects that are not eligible for the Advice Letter/notice process but have already undergone CEQA review, PG&E would likely be able to file a "short-form" CPCN or PTC application, which takes about 4-6 months to process.

Please see Section III, in General Order 131-D. This document can be found in the CPUC's web page at:
http://www.cpuc.ca.gov/PUBLISHED/GENERAL_ORDER/589.htm

9.2 CPUC Section 851

Because PG&E is subject to the jurisdiction of the CPUC, it must also comply with Public Utilities Code Section 851. Among other things, this code provision requires PG&E to obtain CPUC approval of leases and licenses to use PG&E property, including rights-of-way granted to third parties for Interconnection Facilities. Obtaining CPUC approval for a Section 851 application can take several months, and requires compliance with the CEQA. PG&E recommends that Section 851 issues be identified as early as possible so that the necessary application can be prepared and processed. As with GO 131-D compliance, PG&E recommends that the project proponent include any facilities that may be affected by Section 851 in the lead agency CEQA review so that the CPUC does not need to undertake additional CEQA review in connection with its Section 851 approval.

10. Technical Requirements

The PG&E Interconnection Handbook explains the technical requirements for interconnection of loads and generators to PG&E's transmission system. The Interconnection Handbook documents facility connection requirements to the PG&E system as required in NERC Standard FAC-001-0. They are based on applicable FERC and CPUC rules and tariffs (e.g., Electric Rules 2, 21 and 22), as well as accepted industry practices and standards. In addition to providing reliability, these technical requirements are consistent with safety for PG&E workers and the public.

The PG&E Interconnection Handbook applies to Retail and Wholesale Entities, which own or operate generation, transmission, and end user facilities that are physically connected to, or desire to physically connect to PG&E's electric system. All technical requirements described or referred to in the Handbook apply to new or re-commissioned Generation Facilities. The Generation Interconnection Handbook comprising sections G-1 through G-5 applies to Generation Entities.

PG&E has established standard operating, metering and equipment protection requirements for loads and generators. The Interconnection Handbook covers such requirements for all transmission-level load and generation entities wishing to interconnect with PG&E's electric system. Additional, project-specific requirements may apply and will be documented in the SIS report.

The PG&E Interconnection Handbook includes, but is not limited to such operating requirements as the following:

- The Project must be able to meet the power factor requirements of 90 percent lagging and 95 percent leading.
- The Project must have Automatic Voltage Regulation (AVR) and be able to maintain the generator voltage under steady-state conditions within ±0.5

percent of any voltage level between 95 percent and 105 percent of the rated generator voltage.

Generators must also meet all applicable CAISO, NERC, and WECC standards. NERC and WECC standards include, but are not limited to such requirements as the following:

- The Project must be able to remain on line during voltage disturbances up to the time periods and associated voltage levels as required by the WECC Low Voltage Ride Through (LVRT) standards that are in-line with FERC Order No. 161-A. The WECC LVRT standard is available on the WECC web site at:

  http://www.wecc.biz/committees/StandingCommittees/PCC/TSS/Shared%20Documents/Voltage%20Ride%20Through%20White%20Paper.pdf

- Currently NERC is working on a Voltage Ride Through standard, PRC-024-1, that would be applicable to all generators interconnecting to the transmission grid. Until PRC-024-1 is effective, PG&E and the CAISO will require that all generators comply with the existing WECC LVRT requirements. The PRC-024-1 standard Draft 1 can be found on the NERC web site at

  http://www.nerc.com/docs/standards/sar/PRC-024-1_Draft1_2009Feb17.pdf

All generators must satisfy the requirements of the PG&E's Interconnection Handbook and meet all applicable CAISO, NERC, and WECC standards. PG&E will not agree to interconnect any new generators unless all technical and contractual requirements are met.

The IC should be aware that the information in the PG&E Interconnection Handbook is subject to change. Parties interconnecting to the PG&E electric system should verify with their PG&E representative that they have the latest versions. The PG&E Interconnection Handbook is available on the PG&E web site at:

http://www.pge.com/about/rates/tariffbook/ferc/tih/

11. Stand-by Power

The SIS will not address any requirements for stand-by power that the Project may require. The IC should contact their PG&E Generation Interconnection Services representative regarding this service.

Note: The IC is urged to contact their PG&E Generation Interconnection Services representative promptly regarding stand-by service in order to ensure its availability for the Project start-up date.

12. Study Updates

This SIS will be performed in accordance to the assumptions listed in the Sections titled "Study Assumptions" and "Power Flow Study Base Cases". In the event that these assumptions are changed, an updating study may be required to re-evaluate the Project's interconnection impact on the CAISO controlled-grid. The IC would be responsible for paying for any such updating study.

ATTACHMENT 1 – GENERATION QUEUE PROJECTS

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
Q0006	Confidential	Tesla Substation	1156	11/30/2014	Yes
Q0016 (P0302)	Confidential	Divide – Cabrillo #2 115 kV Line	55.5	12/31/2011	Yes
Q0022 (P0304)	Confidential	Birds Landing Switching Station	38	12/31/2010	Yes
Q0037 (P0409)	Confidential	Tesla Substation	74.9	12/31/2011	Yes
Q0038 (P0411)	Confidential	Humboldt Power Plant Substation	146.4	7/15/2010	Yes
Q0039 (P0412)	Confidential	Birds Landing Switching Station	200	12/22/2009	Yes
Q0042 (P0418)	Confidential	McCall Substation 115 kV Bus	300	3/31/2013	Yes
Q0045 (P0424)	Confidential	Eastshore Substation	361	6/1/2012	Yes
Q0057 (P0506)	Confidential	Cottonwood – Vaca Dixon 230 kV lines	715	5/1/2010	Yes
Q0060 (P0513)	Confidential	Kern Oil Substation 115 kV	94	3/31/2013	Yes
Q0067 (P0526)	Confidential	Eastshore 230 kV Bus	245	6/1/2012	Yes
Q0074 (P0528L)	Confidential	Pit 3 – Round Mountain 230 kV Line	102	12/15/2010	Yes
Q0108 (P0609L)	Confidential	Lambie – Contra Costa 230 kV	128	3/5/2012	Yes
Q0111 (P0610L)	Confidential	Chevron 70 kV Tap	16	12/15/2012	Yes
Q0113 (P0611L)	Confidential	Birds Landing Switching Station	30	4/1/2012	Yes
Q0166 (P0701L)	Confidential	Morro Bay – Midway 230 kV Line	210	12/31/2013	Yes
Q0172 (P0703L)	Confidential	Tesla – Bellota 230 kV Line	508	5/1/2014	Yes
Q0184 (P0706)	Confidential	Geysers #3 – Cloverdale 115 kV Line	35	12/15/2010	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
Q0194 (P0709)	Confidential	Morro Bay – Midway 230 kV Lines	190	9/1/2013	Yes
Q0212	Confidential	Rio Dell Substation 60 kV	50	10/30/2010	Yes
Q0222	Confidential	Birds Landing Switching Station	78	12/31/2011	No (Trans. Cluster)
Q0239	Confidential	Morro Bay – Midway 230 kV Lines	250	12/31/2011	No (Trans. Cluster)
Q0242	Confidential	Morro Bay – Midway 230 kV Lines	150	12/31/2013	No (Trans. Cluster)
Q0248	Confidential	Tesla – Bellota 230 kV Line	67	5/1/2014	Yes
Q0250	Confidential	Redbud – Cortina 115 kV Line	66.2	12/31/2012	No (Trans. Cluster)
Q0254	Confidential	Gates Substation 230 kV	600	6/1/2012	No (Trans. Cluster)
Q0258	Confidential	Contra Costa Substation	651	12/1/2013	No (Trans. Cluster)
Q0267	Confidential	Gold Hill – Eight Mile 230 kV Line	280	4/16/2012	Yes
Q0268	Confidential	Tesla – Manteca 115 kV Line Via Schulte Swyd	145	4/1/2013	Yes
Q0272	Confidential	Henrietta Substation 70 kV	150	5/1/2013	No (Trans. Cluster)
Q0282	Confidential	Tap Dairyland – Mendota 115 kV Line	8	12/31/2010	No (Trans. Cluster)
Q0299	Confidential	Hanford Switchyard 115 kV Bus	27	5/1/2013	No (Trans. Cluster)
Q0300	Confidential	Midway – Wheeler Ridge 230 kV Lines	400	9/1/2015	No (Trans. Cluster)
Q0304	Confidential	Smyrna – Alpaugh 115 kV Line	50	12/31/2012	No (Trans. Cluster)
Q0320	Confidential	Contra Costa PP 230 kV Switchyard	100 (Sum) 214 (Win)	5/1/2013	No (Trans. Cluster)
Q0334	Confidential	Kelso Substation 230 kV Bus	195.9	7/1/2012	No (Trans. Cluster)
Q0340	Confidential	Smyrna – Alpaugh 115 kV Line	20	4/1/2011	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
Q0356	Confidential	Taft – Cuyama #1 70 kV	40	1/1/2013	No (Trans. Cluster)
Q0372	Confidential	Jacobs Corner Substation 70 kV Bus	20	11/1/2010	Yes
Q0378	Confidential	Los Esteros Substation 115 kV Bus	120	6/1/2013	No (Trans. Cluster)
Q0417	Confidential	Pittsburg – Tesla 230 kV	14	9/30/2010	No (Trans. Cluster)
Q0470	Confidential	Jacobs Corner Substation 70 kV Bus	20	3/1/2011	Yes
Q0471	Confidential	Jacobs Corner Substation 70 kV Bus	20	7/1/2011	Yes
Q0473	Confidential	Smyrna – Alpaugh 115 kV Line	20	7/1/2011	Yes
Q0476	Confidential	Lakeville #2 60 kV Line	9.9	5/29/2010	Yes
Q0477	Confidential	Centerville – Table Mountain 60 kV Line	4	4/17/2011	Yes
Q0478	Confidential	Corcoran – Kingsburg #2 115 kV Line	20	11/1/2011	Yes
Q0479	Confidential	Smyrna – Alpaugh 115 kV Line	20	10/1/2011	Yes
Q0481	Confidential	Valley Spring – Martel #2 60 kV Line	18.4	4/1/2010	Yes
W009	Confidential	El Capitan Substation	0.75	4/1/2010	Yes
W012	Confidential	Sand Creek Substation	4	12/1/2010	Yes
W014	Confidential	Blackwell Substation	12.5	7/30/2010	Yes
W019	Confidential	Avenal 70 kV Tap Line	20	3/1/2011	Yes
Q0482	Confidential	Smyrna – Alpaugh 115 kV Line	20	4/1/2012	Yes
W020	Confidential	Avenal 70 kV Tap Line	6	3/31/2010	Yes
Q0484	Confidential	Arco – Carneras 70 kV Line	20	9/30/2011	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	Project Name	Nearest Facility	Capacity (MW)	Expected On-Line Date	Modeled In Study Cases
W022	Confidential	Avenal 70 kV Tap Line	19	4/30/2011	Yes
W023	Confidential	Newark Substation - 12 kV Distribution	4.8	4/15/2010	Yes
W024	Confidential	Edenvale Substation - 21 kV Distribution	6.4	8/20/2010	Yes
W025	Confidential	Goose Lake Substation	15	6/1/2011	Yes
W026	Confidential	Smyrna Substation	10	6/1/2011	Yes
W029	Confidential	Smyrna Substation	10	6/1/2011	Yes
Q0489	Confidential	Birds Landing Switching Station	98.9	5/31/2011	No (Cluster 1)
Q0495	Confidential	Tulloch 115 kV Tap	7.2	10/1/2011	No (Cluster 1)
Q0514	Confidential	Arco Substation 70 kV Bus	20	11/1/2012	Yes
W030	Confidential	Twisselman Substation	20	12/15/2010	Yes
W031	Confidential	Tupman Substation	0.6	12/1/2010	Yes
W032	Confidential	Coalinga #2 Substation	20	12/1/2010	Yes
Q0517	Confidential	Kern – Old River #1 70 kV Line	20	12/31/2012	Yes
Q0523	Confidential	Arco Substation 70 kV Bus	20	10/30/2011	Yes
W033	Confidential	Oroville Substation - 12 kV Distribution	3	8/1/2011	Yes
Q0526	Confidential	Schindler – Coalinga #2 70 kV Line	20	1/1/2012	Yes
W036	Confidential	Lakeview Substation - 12 kV Distribution	20	12/1/2010	Yes
W041	Confidential	Kettleman Hills - 12 kV Distribution	20	12/1/2010	Yes
W044	Confidential	Elk Hills Substation – 12 kV Distribution	10	12/1/2010	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
W045	Confidential	Coalinga #1 Substation - 12 kV Distribution	20	12/1/2010	Yes
W046	Confidential	Firebaugh Substation - 12 kV Distribution	10	5/1/2011	Yes
W047	Confidential	Oro Loma Substation - 12 kV Distribution	20	5/1/2011	Yes
Q0528	Confidential	Birds Landing Switching Station	20	6/1/2011	Yes
W048	Confidential	Oro Loma Substation - 12 kV Distribution	20	5/1/2011	Yes
W050	Confidential	El Nido Substation	4.2	12/1/2010	Yes
W051	Confidential	Fulton Substation	2		Yes
W052	Confidential	Giffen Substation - 12 kV Distribution	20	12/1/2010	Yes
W053	Confidential	Merced Substation	3.1	12/1/2010	Yes
W054	Confidential	Schindler Substation - 12 kV Distribution	15	12/1/2010	Yes
W055	Confidential	Schindler Substation - 12 kV Distribution	15	12/1/2010	Yes
Q0529	Confidential	Corcoran – Kingsburg #1 115 kV Line	20	8/1/2013	Yes
Q0529A	Confidential	Helm – Kerman 70 kV Line	14.5	4/1/2011	Yes
Q0530	Confidential	Corcoran – Smyrna 115 kV line	20	7/1/2011	Yes
Q0532	Confidential	Schindler – Huron – Gates 70 kV Line	20	1/1/2012	Yes
Q0534	Confidential	Moss Landing – Panoche #2 230 kV Line	20	6/1/3011	Yes
W057	Confidential	Blackwell Substation	12	6/1/2011	Yes
W058	Confidential	Vaca Dixon Substation - 12 kV Distribution	10	12/1/2010	Yes
W059	Confidential	Hick Substation	4.8		Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
W060	Confidential	Le Grand Substation - 12 kV Distribution	15	12/11/2011	Yes
W061	Confidential	Cheney Substation - 12 kV Distribution	20	3/30/2011	Yes
W062	Confidential	Huron Substation - 12 kV Distribution	20	3/30/2011	Yes
Q0535	Confidential	Los Banos – Canal – Oro Loma 70 kV Line	20	10/31/2011	Yes
W063	Confidential	Gates Substation - 12 kV Distribution	20	6/30/2011	Yes
W064	Confidential	Gates Substation - 12 kV Distribution	20	6/30/2011	Yes
W065	Confidential	Stroud Substation - 12 kV Distribution	20	6/30/2011	Yes
W066	Confidential	Cantua Substation - 12 kV Distribution	20	6/30/2011	Yes
Q0538	Confidential	Oro Loma – Mendota 70 kV Line	20	1/1/2012	Yes
Q0539	Confidential	Salado – Newman 60 kV Line No. 1	20	6/1/2011	Yes
Q0541	Confidential	Panoche – Oro Loma 115 kV Line	20	1/1/2012	Yes
Q0542	Confidential	Schindler Substation 115 kV Bus	20	1/1/2012	Yes
Q0543	Confidential	Schindler Substation 70 kV Bus	20	1/1/2012	Yes
Q0545	Confidential	Wheeler Ridge – Lakeville 70 kV Line	20	10/31/2011	Yes
W067	Confidential	Anita Substation	8.3	10/31/2011	Yes
Q0550	Confidential	Merced #1 70 kV Line	20	12/15/2011	Yes
Q0551	Confidential	Wheeler Ridge – San Bernard 70 kV Line	20	10/31/2011	Yes
W070	Confidential	El Nido Substation	14	12/1/2011	Yes
Q0553	Confidential	Moss Landing – Panoche 230 kV Line	400	12/15/2013	No (Cluster 2)

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
Q0554	Confidential	Pit River – Cottonwood 230 kV Line	138	10/31/2013	No (Cluster 2)
Q0557	Confidential	Smyrna – Alpaugh 115 kV Line	19.75	4/1/2013	No (Cluster 2)
Q0558	Confidential	Corcoran – Kingsburg # 2 115 kV Line	19.75	6/1/2013	No (Cluster 2)
Q0559	Confidential	Wheeler Ridge – Lamont 115 kV Line	80	7/1/2012	No (Cluster 2)
Q0560	Confidential	Los Banos – Dos Amigos 230 kV Line	150	7/1/2012	No (Cluster 2)
Q0568	Confidential	Eastshore Substation	25	5/1/2013	No (Cluster 2)
Q0569	Confidential	Table Mountain –Tesla 500 kV Line	600	5/1/2013	No (Cluster 2)
Q0577	Confidential	Los Banos – Westley 230 kV Line	220	12/31/2013	No (Cluster 2)
Q0579	Confidential	Borden Substation 230 kV Bus	220	5/1/2013	No (Cluster 2)
Q0581	Confidential	Henrietta Substation 70 kV Bus	100	5/1/2013	No (Cluster 2)
Q0586	Confidential	Geysers #17 – Fulton 230 kV Line	99.8	6/1/2013	No (Cluster 2)
Q0592	Confidential	Midway – Gates and Arco – Gates 230 kV Lines	500	12/31/2012	No (Cluster 2)
Q0600	Confidential	Merced #1 70 kV Line	20	12/31/2012	No (Cluster 2)
Q0606	Confidential	Schulte Switching Station 115 kV Bus	20	6/1/2012	No (Cluster 2)
Q0607	Confidential	Mendota Substation 115 kV Bus	60	10/1/2012	No (Cluster 2
Q0610	Confidential	Stroud Sw Sta – Schindler 70 kV Line	20	12/1/2012	Yes
W072	Confidential	7th Standard Substation	20	2/1/2011	Yes
W073	Confidential	Stone Corral Substation - 12 kV Distribution	2	4/1/2011	Yes
W074	Confidential	Giffen Substation - 12 kV Distribution	16	12/1/2011	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
W076	Confidential	Corcoran Substation - 12 kV Distribution	16	4/1/2011	Yes
W077	Confidential	Corcoran Substation - 12 kV Distribution	20	12/1/2011	Yes
W078	Confidential	Santa Nella Substation - 12 kV Distribution	6	4/1/2011	Yes
W079	Confidential	Saratoga Substation	0.1	6/30/2010	Yes
W079a	Confidential	Olema Substation	0.08	3/1/2010	Yes
W079b	Confidential	Deepwater Substation	20	8/31/2010	Yes
W081	Confidential	Twisselman Substation	1.5	6/1/2011	Yes
W083	Confidential	Colusa Junction Sub - 12 kV Distribution	20	1/1/2011	Yes
Q0612	Confidential	Panoche – Schindler 115 kV Line	20	1/1/2012	Yes
Q0613	Confidential	Helm Substation 70 kV bus	20	1/1/2012	Yes
W090	Confidential	San Joaquin Substation - 12 kV Distribution	5.5	12/31/2010	Yes
W091	Confidential	San Joaquin Substation – 12 kV Distribution	20	12/1/2012	Yes
Q0614	Confidential	Merced #1 70kV Line	20	5/1/2011	Yes
W095a	Confidential	Peabody Substation	4.8	4/1/2014	Yes
Q0617	Confidential	Tesla – Tracy 115 kV Line	20	3/1/2011	Yes
W096	Confidential	Twisselman Substation - 12 kV Distribution	15	12/1/2013	Yes
W097	Confidential	Twisselman Substation - 12 kV Distribution	15	12/1/2013	Yes
Q0617B	Confidential	Corcoran – Smyrna 115 kV Line	19.7	12/1/2012	Yes
Q0618	Confidential	Schindler – Coalinga #2 70 kV Line	20	8/1/2012	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	Project Name	Nearest Facility	Capacity (MW)	Expected On-Line Date	Modeled In Study Cases
W099	Confidential	Gates Substation	10	12/1/2013	Yes
W100	Confidential	Copus Substation - 12 kV Distribution	20	5/1/2011	Yes
W103	Confidential	Old River Substation	5	12/31/2011	Yes
W104	Confidential	Tyler Substation - 12 kV Distribution	20	9/1/2011	Yes
Q0620	Confidential	Maricopa – Copus 70 kV Line	20	12/31/2011	Yes
Q0620A	Confidential	Lakeview Substation	20	12/31/2011	Yes
W105	Confidential	Copus Substation	10	12/31/2011	Yes
W106	Confidential	Lakeview Substation	20	12/31/2011	Yes
W107	Confidential	Chowchilla Substation	2	9/1/2011	Yes
W108	Confidential	El Peco Substation	3.5	9/1/2011	Yes
W109	Confidential	Stone Corral Substation	7	9/1/2011	Yes
W110	Confidential	Goose Lake Substation	3	9/1/2011	Yes
W111	Confidential	San Bernard Substation	6	6/1/2011	Yes
W112	Confidential	Avenal Substation	20	5/1/2011	Yes
Q0621A	Confidential	Weedpatch – San Bernard 70 kV Line	20	3/31/2011	Yes
Q0622	Confidential	Carneras – Taft 70 kV Line	9.25	12/1/2011	Yes
Q0622B	Confidential	Wheeler Ridge – Lamont 115 kV Line	20	3/31/2012	Yes
W116	Confidential	Copus Substation	20	12/1/2014	Yes
W117	Confidential	San Bernard Substation	10	12/1/2014	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	Project Name	Nearest Facility	Capacity (MW)	Expected On-Line Date	Modeled In Study Cases
W118	Confidential	San Bernard Substation	10	12/1/2014	Yes
Q0625	Confidential	Henrietta – Tulare Lake 70 kV Line	20	12/31/2011	Yes
Q0626	Confidential	Henrietta – Guernsey 70 kV Line	20	12/31/2011	Yes
Q0629	Confidential	Miller Tap #2 115 kV Line	20	12/1/2011	Yes
Q0631	Confidential	Stroud SW STA – Stroud 70 kV Line	20	6/30/2012	Yes
W119	Confidential	Cuyama Substation	20	9/1/2011	Yes
W120	Confidential	Tupman Substation	20	10/1/2011	Yes
Q0632	Confidential	Wesix 70 kV Tap	19	12/31/2012	Yes
W121	Confidential	Guernsey Substation	20	4/30/2011	Yes
Q0632A	Confidential	Miller Tap #2 115 kV Line	20	12/1/2011	Yes
Q0632B	Confidential	Stroud SW STA – Stroud 70 kV Line	20	12/1/2012	Yes
Q0632C	Confidential	Helm – Stroud SW STA 70 kV Line	20	12/1/2012	Yes
W122	Confidential	Arvin Substation	10	3/31/2012	Yes
W125	Confidential	Lamont Substation	20	4/1/2012	Yes
W126	Confidential	Putah Creek 12 kV	3	2/1/2011	Yes
Q0633	Confidential	Gates – Coalinga #1 70 kV Line	20	7/10/2011	Yes
W129	Confidential	El Nido Substation	5	6/15/2012	Yes
W130	Confidential	El Nido Substation	10	9/15/2013	Yes
W131	Confidential	Stroud Substation	20	1/1/2012	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	Project Name	Nearest Facility	Capacity (MW)	Expected On-Line Date	Modeled In Study Cases
W132	Confidential	Stroud Substation	20	1/1/2012	Yes
W132A	Confidential	Novato Substation	1	1/1/2011	Yes
W133	Confidential	Huron Substation	20	6/1/2012	Yes
Q0634	Confidential	Camden Jct. – Lemoore Tap 70 kV Line	20	12/31/2012	Yes
Q0635	Confidential	Oro Loma-Canal #1 70 kV Line	20	6/15/2012	Yes
Q0636	Confidential	Leprino 115 kV Tap Line	20	12/31/2012	Yes
Q0637	Confidential	Guernsey – Henrietta 70 kV Line	20	12/31/2012	Yes
Q0638	Confidential	Gates – Coalinga #1 70 kV Line	15	12/31/2012	Yes
W134	Confidential	Coalinga #1 Substation - 12 kV Distribution	4	12/31/2011	Yes
Q0640A	Confidential	Schindler Substation 115 kV bus	20	12/15/2011	Yes
Q0640B	Confidential	Oro Loma Substation 115 kV bus	20	12/15/2011	Yes
W135	Confidential	Oro Loma Substation - 12 kV Distribution	20	4/30/2012	Yes
W136	Confidential	Oro Loma Substation - 12 kV Distribution	20	4/1/2012	Yes
W138	Confidential	Gates Substation - 12 kV Distribution (1105)	5	4/1/2011	Yes
W139	Confidential	Gates Substation - 12 kV Distribution (1104)	5	4/28/2011	Yes
Q0641	Confidential	Midsun – Midway 115 kV Line	11.2	12/31/2011	Yes
Q0642	Confidential	Elk Creek 60 kV Tap	20	7/1/2011	Yes
Q0643	Confidential	Los Banos – San Luis PGP #1 230 kV Line	149.5	12/31/2014	Yes
Q0643A	Confidential	Arco Substation 230 kV bus	300	12/31/2014	No (Cluster 3)

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
Q0643D	Confidential	Angiola Substation 70 kV bus	150	12/31/2014	No (Cluster 3)
Q0643E	Confidential	Schindler Substation 115 kV bus	175	12/31/2014	No (Cluster 3)
Q0643F	Confidential	Rio Oso – Lockeford 230 kV Line	220	3/1/2014	No (Cluster 3)
Q0643G	Confidential	Cascade – Cottonwood 115 kV Line	27.15	3/1/2012	No (Cluster 3)
Q0643H	Confidential	Gates – Gregg 230 kV Line	600	5/1/2015	No (Cluster 3)
Q0643I	Confidential	Mendota – Dairyland 115 kV Line	200	3/1/2014	No (Cluster 3)
Q0643J	Confidential	Schindler – Coalinga #2 70 kV Line	169	4/1/2017	No (Cluster 3)
Q0643K	Confidential	Mendota – San Joaquin – Helm 70 kV Line	289	4/1/2017	No (Cluster 3)
Q0643L	Confidential	Panoche – Schindler 115 kV Lines #1 & #2	289	4/1/2017	No (Cluster 3)
Q0643M	Confidential	Panoche – Schindler 115 kV Lines #1 & #2	289	4/1/2017	No (Cluster 3)
Q0643N	Confidential	Helm – Stroud Sw Sta 70 kV Line	169	4/1/2017	No (Cluster 3)
Q0643O	Confidential	Brighton – Davis 115 kV Line	150	3/1/2014	No (Cluster 3)
Q0643W	Confidential	Gates – Gregg and Gates – McCall 230 kV Lines	200	6/30/2014	No (Cluster 3)
Q0643X	Confidential	Helm – Panoche and Kearney – Panoche 230 kV Lines	500	1/30/2014	No (Cluster 3)
Q0643Y	Confidential	Henrietta – Leprino Foods 115 kV Line	80	7/1/2013	No (Cluster 3)
W140	Confidential	Jolon Substation - 12 kV Distribution	8.5	12/15/2012	Yes
W141	Confidential	San Miguel Substation - 12 kV Distribution	12	12/15/2012	Yes
W142	Confidential	Le Grand Substation - 12 kV Distribution	20	10/31/2011	Yes
W143	Confidential	McFarland Substation - 12 kV Distribution	18.3	12/1/2011	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
W144	Confidential	Maricopa Substation - 12 kV Distribution	11.5	12/15/2012	Yes
W145	Confidential	Jolon Substation - 12 kV Distribution	3	11/1/2011	Yes
W146	Confidential	Jolon Substation - 12 kV Distribution	3	12/1/2011	Yes
Q0644	Confidential	Dairyland – Le Grand 115 kV Line	20	1/1/2012	Yes
Q0645	Confidential	Jolon Substation 60 kV bus	20	2/1/2012	Yes
W147	Confidential	Herdlyn Substation - 12 kV Distribution	10	2/1/2011	Yes
Q0645A	Confidential	Weedpatch – Wheeler Ridge 70 kV Line	20	12/1/2012	Yes
Q0646	Confidential	Cheney #1 115 kV Tap Line	12	3/1/2013	Yes
Q0647	Confidential	Oro Loma Substation 115 kV bus	20	4/30/2012	Yes
Q0648	Confidential	Oro Loma Substation 70 kV bus	20	4/30/2012	Yes
Q0649	Confidential	Helm Substation 70 kV bus	11.75	3/1/2013	Yes
W148	Confidential	Cayetano Substation - 12 kV Distribution	4.308	12/1/2011	Yes
W150	Confidential	Santa Rita Substation - 12 kV Distribution	3	12/15/2012	Yes
W151	Confidential	Twisselman Substation - 12 kV Distribution	3	4/1/2011	Yes
W152	Confidential	Avenal Substation - 12 kV Distribution	3	9/1/2011	Yes
W153	Confidential	Avenal Substation - 12 kV Distribution	3	9/1/2011	Yes
W154	Confidential	Malaga Substation - 12 kV Distribution	1.75	3/1/2012	Yes
W155	Confidential	Corral Substation - 12 kV Distribution	2.154	12/31/2011	Yes
Q0650	Confidential	Panoche – Schindler #2 115 kV Line	20	12/25/2011	Yes

PG&E Area Generation Projects - CAISO Generation Interconnection Queue					
Queue Position	**Project Name**	**Nearest Facility**	**Capacity (MW)**	**Expected On-Line Date**	**Modeled In Study Cases**
W156	Confidential	Storey Substation - 12 kV Distribution	3	9/1/2011	Yes
W157	Confidential	Merced Falls Substation - 21 kV Distribution	3	9/1/2011	Yes
W158	Confidential	Merced Falls Substation - 21 kV Distribution	3	9/1/2011	Yes
W159	Confidential	Le Grand Substation - 12 kV Distribution	3	9/1/2011	Yes
W160	Confidential	Le Grand Substation - 12 kV Distribution	3	9/1/2011	Yes
Q0651	Confidential	Plumas Substation 60 kV bus	20	6/1/2012	Yes
W164	Confidential	TBD	5	5/31/2012	Yes
Q0652	Confidential	Kerckhoff – Clovis – Sanger #1 115 kV Line	20	6/15/2013	Yes
W166	Confidential	Prunedale Substation - 12 kV Distribution	4.308	TBD	Yes
653	Confidential	Arco – Tulare Lake 70 kV Line	20	1/15/2013	Yes
653A	Confidential	Arco Substation 70 kV bus	20	1/15/2013	Yes
W171	Confidential	Schindler Substation - 12 kV Distribution	20	12/1/2013	Yes
654	Confidential	Goose Lake Substation 115 kV bus	20	5/20/2013	Yes

System Impact Study Plan

Generation Interconnection (Wholesale)

Port of Stockton, California

Rough & Ready Island Solar Project

FINAL

Pacific Gas and Electric Company

WE DELIVER ENERGY.

July 17, 2013

Table of Contents

1. Introduction

Port of Stockton, pursuant to Section 11.2 of the Interconnection Agreement between Pacific Gas & Electric Company (PG&E) and the Stockton Port District, has submitted an interconnection request for their Rough & Ready Island Solar Project (Project).

The Project would add 2.0 MW of solar photovoltaic generation to the Port of Stockton's 12 kV distribution system, which is currently connected to PG&E's Rough & Ready 70 kV Substation. The proposed Commercial Operation Date (COD) of the Project is December 31, 2014.

PG&E has accepted the Port of Stockton's interconnection request under PG&E's Transmission Owner Tariff (TO). PG&E will proceed with a System Impact Study (SIS) to determine the impact of the Project on PG&E's electric transmission system. This SIS will identify:

- PG&E transmission system impacts caused solely by the addition of the Project;
- PG&E system reinforcements necessary to mitigate any adverse impacts of the Project under various system conditions; and
- PG&E facilities required for system reinforcements with a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct.

This SIS will not address the CAISO requirements for a Delivery Assessment for determining the character of power being delivered, including its qualifications for Resource Adequacy. The Port of Stockton is urged to contact the CAISO so they can perform the necessary studies to make this determination.

This study plan will form the basis for the SIS Agreement by defining the scope, content, assumptions, and terms of reference of the SIS.

2. Study Fee

PG&E has estimated a study fee of $20,000 for performing this SIS based upon the scope of this study plan. The final cost to complete this SIS will be based on actual cost. If the Port of Stockton chooses not to continue with the study after receiving this Study Plan, a fee of $1,000 shall be assessed to reimburse PG&E the cost of processing the study request, and the Port of Stockton shall have no further obligations to PG&E pursuant to the study plan or the SIS.

PG&E will provide the Port of Stockton a record of actual costs for performing this SIS roughly three months after the SIS is completed. PG&E will bill the Port of Stockton the remaining balance if the actual cost is higher than the estimated $20,000.

If the actual cost is less than the estimated study fee, PG&E will return the balance to the Port of Stockton within thirty (30) days of such determination.

3. Schedule

Table 3-1 shows the preliminary milestones/schedules associated with the study.

Table 3-1: Preliminary Study Schedule

Task	Milestone Description	Target Date
1	Tender Draft SIS Study Plan / Study Agreement	April 24, 2013
2	Port of Stockton final comments on Draft SIS Study Plan	July 17, 2013
3	PG&E finalizes Study Plan	July 17, 2013
4	Port of Stockton signs and returns Study Agreement	July 22, 2013
6	PG&E submits draft SIS Report for review	September 13, 2013
7	Port of Stockton submits comments on draft SIS Report	September 27, 2013
8	PG&E finalizes SIS Report	October 4, 2013

4. Cost Estimates

The SIS will provide a list of required facilities with a non-binding good faith estimate of cost responsibility and high-level construction timetable for these required facilities. This cost and schedule have no associated degree of accuracy in the SIS and are provided for informational purpose only.

Detailed cost estimates and work scope will be provided if the Project progresses to a Facilities Study (FAS).

5. Project and Interconnection Information

Table 5-1 provides general information about the Project as provided in the interconnection request.

Table 5-1: Project General Information

Project Location	Stockton, CA
PG&E Planning Area	Stockton Division (Central Valley)
Type of Generators	Solar – Xantrex Model
Maximum Generator Output	2.0 MW
Generator Auxiliary Load	0 MW
Maximum Net Output	2.0 MW
Power Factor	0.99
Step-up Transformer	Existing at PG&E's Rough & Ready Substation

Description Of Interconnection	PG&E Rough & Ready Substation
Connection Voltage	60 kV

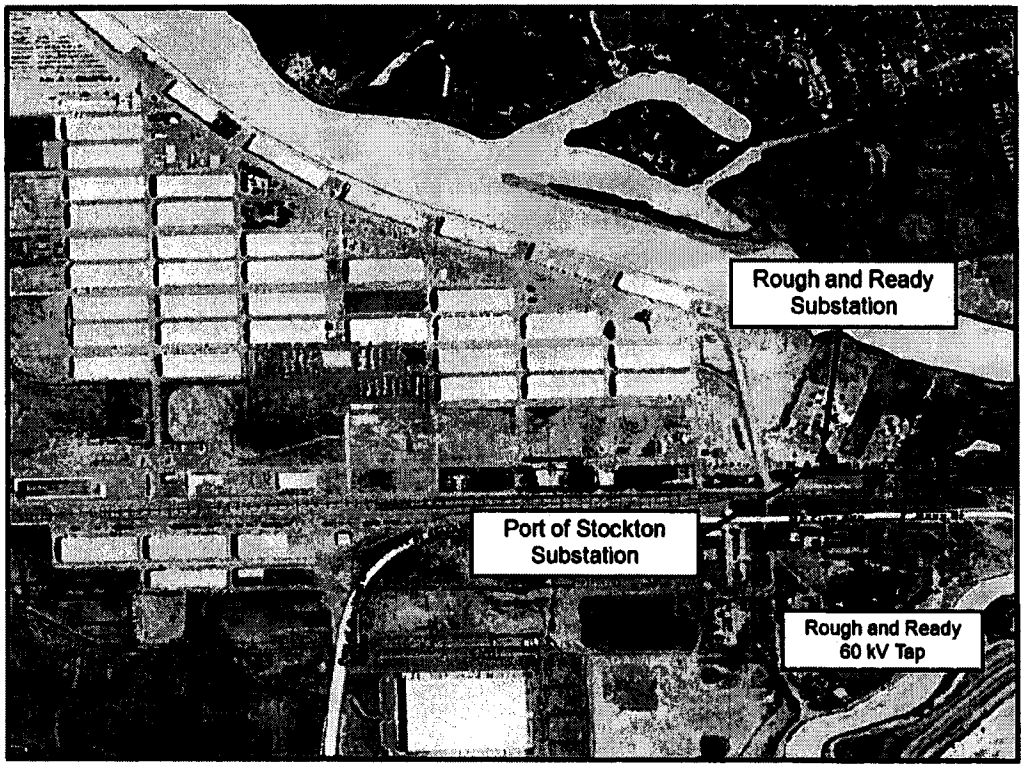

Figure 5-1 – Vicinity Map

6. Study Assumptions

PG&E will conduct the SIS under the following assumptions:

1) The maximum net output of the Project is 2.0 MW.

2) The expected Commercial Operation Date of the Project is December 31, 2014.

3) The Port of Stockton will engineer, procure, construct, own, operate and maintain its Project facility.

4) The SIS will take into account all approved PG&E transmission projects and proposed generating facilities in PG&E's Central Valley Area that will be operational by December 31, 2014.

7. Power Flow Study Base Cases

Power flow analyses will be performed to ensure that PG&E's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results of these power flow analyses will serve as documentation that an evaluation of the reliability impact of this new facility and its connection to interconnected transmission systems has been performed. If a NERC reliability problem exists as a result of this interconnection, it will be PG&E's responsibility to identify the problem and develop an appropriate corrective action plan to comply with NERC reliability standards.

As part of PG&E's obligations with NERC as the registered Transmission Owner for the PG&E transmission system, the study results for this interconnection will be communicated to the California Independent System Operator Corporation (CAISO), or other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities are solicited to ensure coordination of transmission systems.

Two (2) power flow base cases will be used to evaluate the transmission system impacts of the Project. While it is impossible to study all combinations of system load and generation levels during all seasons and at all times of the day, these base cases represent extreme loading and generation conditions for the study area.

- 2015 Summer Peak Area Base Case:

  Summer peak power flow base cases will be used to evaluate the transmission system impacts of the interconnection of the Project on the PG&E system. Power flow analysis will be performed using PG&E's 2015 Summer Peak Base Case (in General Electric Power Flow format). This base case is from PG&E's 2013 base case series and has a 1-in-10 year adverse weather load level for the Central Valley Area.

- 2015 Summer Off-Peak Area Base Case:

  Power flow analysis will also be performed using PG&E's 2015 Summer Off-Peak Base Case (in General Electric Power Flow format) in order to evaluate potential congestion on transmission facilities during the Off-Peak system conditions. The loads in this base case are about 50% of the summer peak loads.

These base cases will model all the CAISO approved PG&E transmission projects that will be operational in 2014 and 2015.

8. Study Scope

The SIS will determine the impact of the Project on PG&E's transmission system. The specific studies conducted are outlined below:

8.1 Steady State Power Flow Analysis

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Pacific Gas and Electric Company

WE DELIVER ENERGY.

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Port of Stockton agrees to pay the study fee of $20,000.

Dated this 9 day of August, 2013

Port of Stockton:

BY: _____
(Signature)

Steve Escobar
(Type or Print Name)

MAILING ADDRESS:

Port of Stockton

P.O. Box 2089

Stockton, CA 95201

1565 E. Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
chris_k@cornerstoneconsulting.biz

CORNERSTONE CONSULTING

Memo

To: Steve Escobar

From: Chris Kiriakou

CC: Juan Villanueva, Dianna Baker

Date: February 13, 2013

Re: Initial Photovoltaic Project Funding

In 2008 Governor Arnold Schwarzenegger signed Executive Order S-14-08 requiring the state's electric utilities to achieve an electric generating portfolio that supplies electricity from 33% renewable resources by 2020. Subsequently, Governor Brown signed Senate Bill X1-2 that specified a timetable with compliance periods leading up to the 33% by 2020 and charged the California Energy Commission (CEC) with the implementation of it. The CEC has developed a draft Renewable Resource Portfolio Standard for publically owned utility implementation of the 2020, 33% requirement.

In December 2012 the Port submitted its plan for compliance with the Renewable Portfolio Standard to the California Energy Commission. The plan approaches compliance from a minimum financial risk, least cost approach and utilizes a combination of purchases and assets to meet the requirement. A primary component of the plan includes the construction of a 1.5 MW Photovoltaic Generating Station located on Rough and Ready Island. The preliminary engineering cost estimate of the plant is $1.8 Million including 10% for contingencies with commercial operation by early 2015.

Initial steps include a study by PG&E for which PG&E has requested a study fee of $30,000 plus initial Port engineering and consulting of $15,000 for a cost of $45,000. A source of funding for the initial costs is the Public Purpose Funds Account that the Port has been collecting funds in retail electric rates since 2008. The December 31, 2012 balance of that account is $220,954. The collection and uses of the funds was mandated by the State in Public Utilities Code 385 (see Attachment 1). Final construction funding of the Photovoltaic Generating Station will be determined as the details of the project costs are known and other funding options identified for the Port.

Recommendation

The Port staff pursue the initial studies and design for a proposed 1.5 MW Photovoltaic Generating Station located at Rough & Ready Island and that funding be made available from the Port's Public Purpose Funds Account.

Attachment 1

Public Utilities Code Section 385(a)

385 (a) Each local publicly owned electric utility shall establish a nonbypassable, usage based charge on local distribution service of not less than the lowest expenditure level of the three largest electrical corporations in California on a percent of revenue basis, calculated from each utility's total revenue requirement for the year ended December 31, 1994, and each utility's total annual expenditure under paragraphs (1), (2), and (3) of subdivision (c) of Section 381 and Section 382, to fund investments by the utility and other parties in any or all of the following:
(1) Cost-effective demand-side management services to promote energy efficiency and energy conservation.
(2) New investment in renewable energy resources and technologies consistent with existing statutes and regulations which promote those resources and technologies.
(3) Research, development and demonstration programs for the public interest to advance science or technology which is not adequately provided by competitive and regulated markets.
(4) Services provided for low-income electricity customers, including, but not limited to, energy efficiency services, education, weatherization, and rate discounts.

Emphasis Added

System Impact Study Plan

Generation Interconnection (Wholesale)

Port of Stockton, California

Rough & Ready Island Solar Project

FINAL

Pacific Gas and Electric Company

WE DELIVER ENERGY.

July 17, 2013

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PG&E has accepted the Port of Stockton's interconnection request under PG&E's Transmission Owner Tariff (TO). PG&E will proceed with a System Impact Study (SIS) to determine the impact of the Project on PG&E's electric transmission system. This SIS will identify:

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- PG&E facilities required for system reinforcements with a non-binding good faith estimate of cost responsibility, and a non-binding good faith estimated time to construct.

This SIS will not address the CAISO requirements for a Delivery Assessment for determining the character of power being delivered, including its qualifications for Resource Adequacy. The Port of Stockton is urged to contact the CAISO so they can perform the necessary studies to make this determination.

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PG&E will provide the Port of Stockton a record of actual costs for performing this SIS roughly three months after the SIS is completed. PG&E will bill the Port of Stockton the remaining balance if the actual cost is higher than the estimated $20,000.

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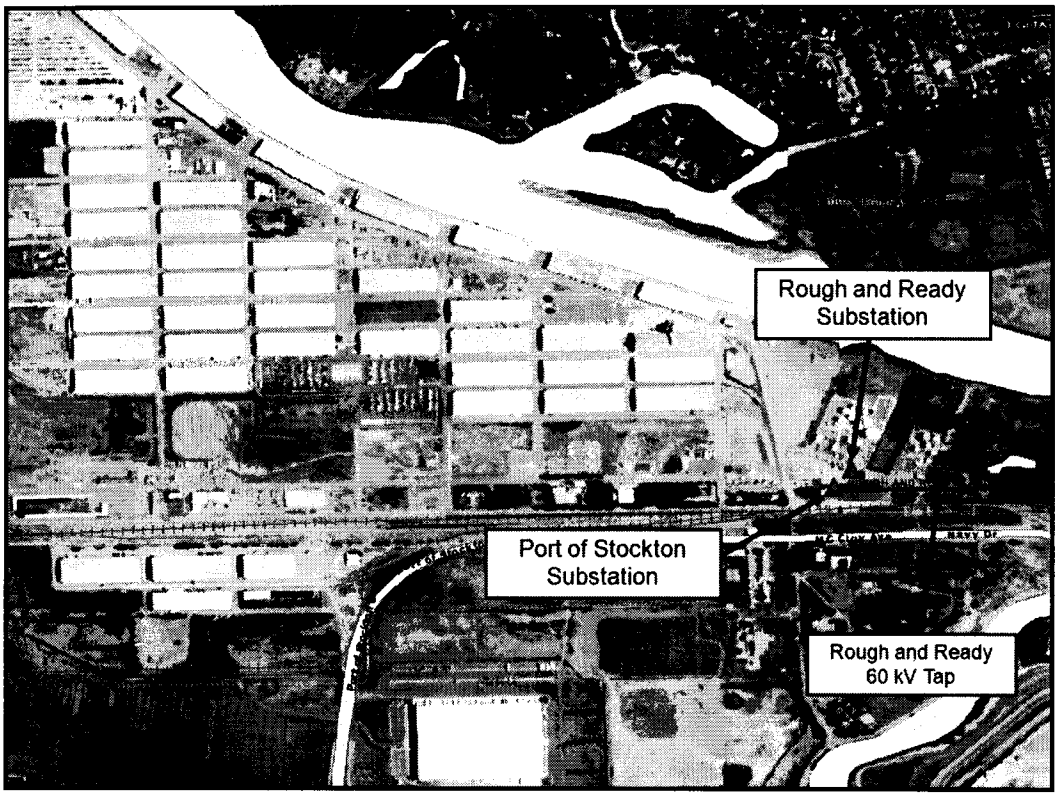
Project Location	Stockton, CA
PG&E Planning Area	Stockton Division (Central Valley)
Type of Generators	Solar – Xantrex Model
Maximum Generator Output	2.0 MW
Generator Auxiliary Load	0 MW
Maximum Net Output	2.0 MW
Power Factor	0.99
Step-up Transformer	Existing at PG&E's Rough & Ready Substation

Description Of Interconnection	PG&E Rough & Ready Substation
Connection Voltage	60 kV



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PG&E will conduct the SIS under the following assumptions:

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Power flow analyses will be performed to ensure that PG&E's transmission system remains in full compliance with North American Reliability Corporation (NERC) reliability standards TPL-001, 002, 003 and 004 with the proposed interconnection. The results of these power flow analyses will serve as documentation that an evaluation of the reliability impact of this new facility and its connection to interconnected transmission systems has been performed. If a NERC reliability problem exists as a result of this interconnection, it will be PG&E's responsibility to identify the problem and develop an appropriate corrective action plan to comply with NERC reliability standards.

As part of PG&E's obligations with NERC as the registered Transmission Owner for the PG&E transmission system, the study results for this interconnection will be communicated to the California Independent System Operator Corporation (CAISO), or other neighboring entities that may be impacted, for coordination and incorporation of its transmission assessments. Input from the CAISO and other neighboring entities are solicited to ensure coordination of transmission systems.

Two (2) power flow base cases will be used to evaluate the transmission system impacts of the Project. While it is impossible to study all combinations of system load and generation levels during all seasons and at all times of the day, these base cases represent extreme loading and generation conditions for the study area.

- 2015 Summer Peak Area Base Case:

  Summer peak power flow base cases will be used to evaluate the transmission system impacts of the interconnection of the Project on the PG&E system. Power flow analysis will be performed using PG&E's 2015 Summer Peak Base Case (in General Electric Power Flow format). This base case is from PG&E's 2013 base case series and has a 1-in-10 year adverse weather load level for the Central Valley Area.

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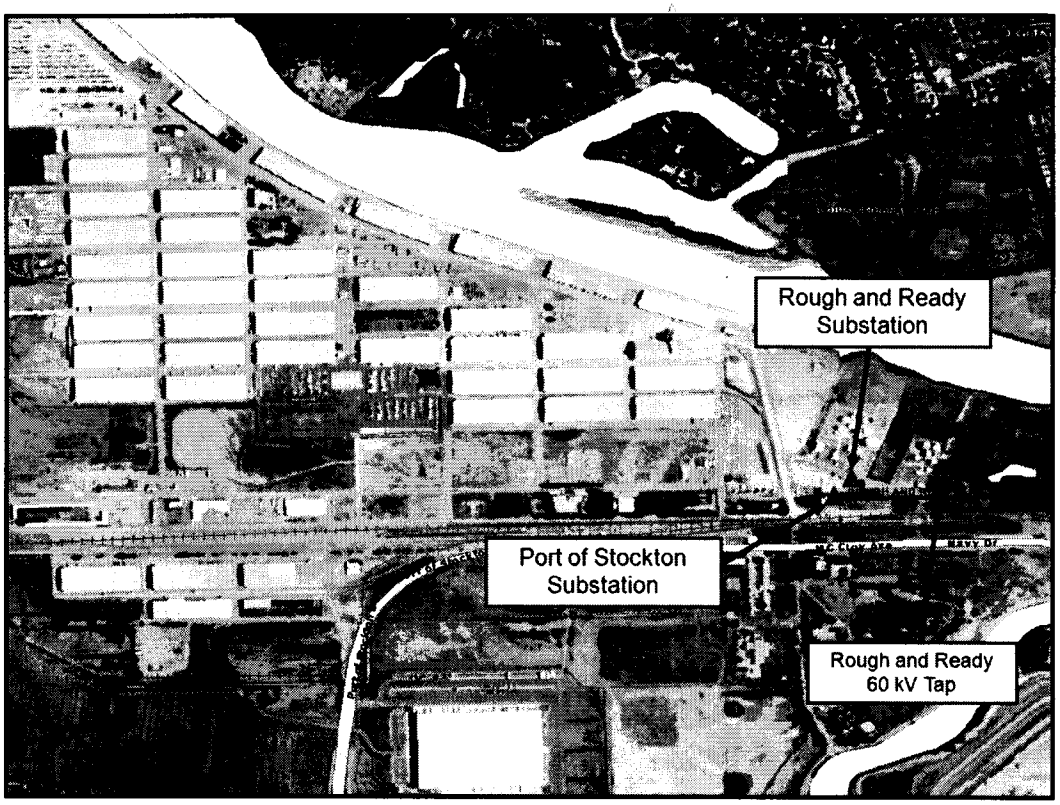

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BY: _____
(Signature)

_____
(Type or Print Name)

MAILING ADDRESS:

_____

_____

_____

_____

Appendix B

Contingency Lists

APPENDIX B – CAISO CATEGORY B CONTINGENCY LIST

```
# PG&E 2013 Assessment Series Stockton Division Area 11 Category B (B1, B2 and B3)

B2_1 "Rio Oso - Lockeford 230 kV Line"
 line     30330  30482  "1 " 1     0     # line   from  RIO OSO      230.00  BRKR to BRKR  LOCKFORD     230.00
0

B2_2 "Gold Hill - Eight Mile Road 230 kV Line"
 line     30337  30622  "1 " 1     0     # line   from  GOLDHILL     230.00  BRKR to BRKR  EIGHT MI     230.00
0

B2_3 "Brighton - Bellota 230 kV Line"
 line     30348  30500  "1 " 1     0     # line   from  BRIGHTON     230.00  BRKR to BRKR  BELLOTA      230.00
0

B2_4 "Lockeford - Bellota 230 kV Line "
 line     30482  30500  "1 " 1     0     # line   from  LOCKFORD     230.00  BRKR to BRKR  BELLOTA      230.00
0

B2_5 "Tiger Creek - Electra 230 kV Line"
 line     30485  30487  "1 " 1     0     # line   from  TIGR CRK     230.00  BRKR to BRKR  ELECTRA      230.00
0

B2_6 "Tiger Creek - Valley Springs 230 kV Line"
 line     30485  30490  "1 " 1     0     # line   from  TIGR CRK     230.00  BRKR to BRKR  VLLY SPS     230.00
0

B2_7 "Electra - Bellota 230 kV Line"
 line     30487  30500  "1 " 1     0     # line   from  ELECTRA      230.00  BRKR to BRKR  BELLOTA      230.00
0

B2_8 "Stagg - Tesla 230 kV Line"
 line     30489  30624  "1 " 1     0     # line   from  STAGG-J2     230.00    (2) to BRKR  TESLA E      230.00
 line     30489  30499  "1 " 1     0     # line   from  STAGG-J2     230.00    (2) to BRKR  STAGG-E      230.00
0

B2_9 "Valley Springs - Bellota 230 kV Line"
 line     30490  30500  "1 " 1     0     # line   from  VLLY SPS     230.00  BRKR to BRKR  BELLOTA      230.00
0

B2_10 "Eight Mile - Stagg 230 kV Line"
 line     30495  30496  "1 " 1     0     # line   from  STAGG        230.00    (2) to BRKR  STAGG-H      230.00
 line     30495  30622  "1 " 1     0     # line   from  STAGG        230.00    (2) to BRKR  EIGHT MI     230.00
0

B2_11 "Bellota - Collierville 230 kV Line No. 1"
 line     30500  30503  "1 " 1     0     # line   from  BELLOTA      230.00  BRKR to BRKR  COLLERVL     230.00
0

B2_12 "Bellota - Collierville 230 kV Line No. 2"
 line     30500  30503  "2 " 1     0     # line   from  BELLOTA      230.00  BRKR to BRKR  COLLERVL     230.00
0

B2_13 "Bellota - Weber 230 kV Line"
 line     30500  30505  "1 " 1     0     # line   from  BELLOTA      230.00  BRKR to BRKR  WEBER        230.00
0

B2_14 "Bellota - Warnerville 230 kV Line"
 line     30500  30515  "1 " 1     0     # line   from  BELLOTA      230.00  BRKR to BRKR  WARNERVL     230.00
0

B2_15 "Bellota - Tesla 230 kV Line No. 2"
 line     30500  30624  "1 " 1     0     # line   from  BELLOTA      230.00  BRKR to BRKR  TESLA E      230.00
0

B2_16 "Bellota - Cottle 230 kV Line"
 line     30500  38206  "1 " 1     0     # line   from  BELLOTA      230.00  BRKR to BRKR  COTTLE       230.00
0

B2_17 "Tesla - Weber 230 kV Line"
 line     30505  30624  "1 " 1     0     # line   from  WEBER        230.00  BRKR to BRKR  TESLA E      230.00
0

B2_18 "Rancho Seco - Bellota 230 kV Line No. 2"
 line     30510  30500  "2 " 1     0     # line   from  CAMANCH      230.00    (3) to BRKR  BELLOTA      230.00
 line     30510  39500  "1 " 1     0     # line   from  CAMANCH      230.00    (3) to (1)   CAMANCPP     230.00
 line     30510  37016  "2 " 1     0     # line   from  CAMANCH      230.00    (3) to BRKR  RNCHSECO     230.00
 load     39500  "1 "    0             # load         CAMANCPP     230.00  LOAD==12.30(5.96)
 load     39500  "E1"    0             # load         CAMANCPP     230.00  LOAD==-0.07(0.00)
0
```

APPENDIX B – CAISO CATEGORY B CONTINGENCY LIST

```
B2_19 "Pittsburg - Tesla 115 kV Line No. 1"
 line     30527  30595  "1 " 1     0     # line   from  PITSBG E     230.00  BRKR to (3)   FLOWIND2     230.00
 line     30595  30640  "1 " 1     0     # line   from  FLOWIND2     230.00   (3) to BRKR  TESLA C      230.00
 tran     30595  33840  "1 "       0     # tran   from  FLOWIND2     230.00   (3) to (1)   FLOWD3-6       9.11
 load     33840  "SG"    0               # load         FLOWD3-6       9.11  LOAD==0.70(0.34)
 gen      33840  "1 "    0               # gen          FLOWD3-6       9.11  GEN ==5.41(0.00)
 gen      33840  "2 "    0               # gen          FLOWD3-6       9.11  GEN ==5.13(0.00)
0

B2_20 "Brentwood - Kelso 230 kV Line"
 line     30565  30569  "1 " 1     0     # line   from  BRENTWOD     230.00  BRKR to BRKR  KELSO        230.00
0

B2_21 "DGC Mariposa Gen - Kelso 230 kV Line"
 line     30568  30569  "1 " 1     0     # line   from  MARIPOSA     230.00   (5) to BRKR  KELSO        230.00
 tran     30568  33813  "1 "       0     # tran   from  MARIPOSA     230.00   (5) to (1)   MARIPCT1      13.80
 tran     30568  33815  "1 "       0     # tran   from  MARIPOSA     230.00   (5) to (1)   MARIPCT2      13.80
 tran     30568  33817  "1 "       0     # tran   from  MARIPOSA     230.00   (5) to (1)   MARIPCT3      13.80
 tran     30568  33819  "1 "       0     # tran   from  MARIPOSA     230.00   (5) to (1)   MARIPCT4      13.80
 load     33813  "ss"    0               # load         MARIPCT1      13.80  LOAD==1.00(0.60)
 load     33815  "ss"    0               # load         MARIPCT2      13.80  LOAD==1.00(0.60)
 load     33817  "ss"    0               # load         MARIPCT3      13.80  LOAD==1.00(0.60)
 load     33819  "ss"    0               # load         MARIPCT4      13.80  LOAD==1.00(0.60)
 gen      33813  "1 "    0               # gen          MARIPCT1      13.80  GEN ==45.95(-1.90)
 gen      33815  "2 "    0               # gen          MARIPCT2      13.80  GEN ==45.95(-1.90)
 gen      33817  "3 "    0               # gen          MARIPCT3      13.80  GEN ==45.95(-1.90)
 gen      33819  "4 "    0               # gen          MARIPCT4      13.80  GEN ==45.95(-1.90)
0

B2_22 "Kelso - Tesla 230 kV Line"
 line     30569  30570  "1 " 1     0     # line   from  KELSO        230.00  BRKR to (4)   USWP-RLF     230.00
 line     30570  30571  "1 " 1     0     # line   from  USWP-RLF     230.00   (4) to (2)   ALTALAND     230.00
 line     30570  30625  "1 " 1     0     # line   from  USWP-RLF     230.00   (4) to BRKR  TESLA D      230.00
 tran     30570  33836  "1 "       0     # tran   from  USWP-RLF     230.00   (4) to (1)   USWP_#4        9.11
 tran     30571  33832  "1 "       0     # tran   from  ALTALAND     230.00   (2) to (1)   COG.CAPT       9.11
 load     33836  "SG"    0               # load         USWP_#4        9.11  LOAD==0.35(0.22)
 gen      33836  "3 "    0               # gen          USWP_#4        9.11  GEN ==11.97(0.00)
 gen      33832  "1 "    0               # gen          COG.CAPT       9.11  GEN ==4.30(-4.40)
0

B2_23 "Delta Switching Yard - Tesla 230 kV Line"
 line     30580  30625  "1 " 1     0     # line   from  ALTM MDW     230.00   (3) to BRKR  TESLA D      230.00
 line     30580  38610  "1 " 1     0     # line   from  ALTM MDW     230.00   (3) to BRKR  DELTAPMP     230.00
 tran     30580  33175  "1 "       0     # tran   from  ALTM MDW     230.00   (3) to (1)   ALTAMONT       9.11
0

B2_24 "Pittsburg - Tesla 115 kV Line No. 2"
 line     30600  30640  "2 " 1     0     # line   from  TRES VAQ     230.00   (3) to BRKR  TESLA C      230.00
 line     30600  30527  "2 " 1     0     # line   from  TRES VAQ     230.00   (3) to BRKR  PITSBG E     230.00
 tran     30600  33171  "1 "       0     # tran   from  TRES VAQ     230.00   (3) to (1)   TRSVQ+NW       9.11
0

B2_25 "Eight Mile Road - Tesla 230 kV Line"
 line     30622  30624  "1 " 1     0     # line   from  EIGHT MI     230.00  BRKR to BRKR  TESLA E      230.00
0

B2_26 "Tesla - Newark 230 kV Line No. 1"
 line     30624  30630  "1 " 1     0     # line   from  TESLA E      230.00  BRKR to BRKR  NEWARK D     230.00
0

B2_27 "Tesla - Westley 230 kV Line"
 line     30624  30670  "1 " 1     0     # line   from  TESLA E      230.00  BRKR to BRKR  WESTLEY      230.00
0

B2_28 "Tesla - Ravenswood 230 kV Line"
 line     30624  30703  "1 " 1     0     # line   from  TESLA E      230.00  BRKR to BRKR  RAVENSWD     230.00
0

B2_29 "Tesla - Newark 230 kV Line No. 2"
 line     30640  30655  "2 " 1     0     # line   from  TESLA C      230.00  BRKR to (3)   ADCC         230.00
 line     30655  30631  "2 " 1     0     # line   from  ADCC         230.00   (3) to BRKR  NEWARK E     230.00
 tran     30655  35310  "1 "       0     # tran   from  ADCC         230.00   (3) to (1)   LFC FIN+       9.11
 gen      35310  "1 "    0               # gen          LFC FIN+       9.11  GEN ==3.36(0.00)
 svd      30655  "v "    0               # svd          ADCC         230.00
0

B2_30 "Gold Hill 60 kV Line No. 1"
 line     32396  33618  "1 " 1     0     # line   from  LIMESTNE       60.00   (2) to (1)   OLETA         60.00
 line     32396  32110  "1 " 1     0     # line   from  LIMESTNE       60.00   (2) to BRKR  GOLD HLL      60.00
```

```
 load     32396  "1 "    0              # load         LIMESTNE      60.00  LOAD==0.03(0.01)
 load     32396  "E1"    0              # load         LIMESTNE      60.00  LOAD==-0.00(0.00)
 load     32396  "EP"    0              # load         LIMESTNE      60.00  LOAD==-0.02(0.00)
 load     32396  "PW"    0              # load         LIMESTNE      60.00  LOAD==0.46(0.39)
 load     33618  "1 "    0              # load         OLETA         60.00  LOAD==7.79(1.11)
 load     33618  "2 "    0              # load         OLETA         60.00  LOAD==3.09(0.44)
 load     33618  "E1"    0              # load         OLETA         60.00  LOAD==-0.03(0.00)
 load     33618  "E2"    0              # load         OLETA         60.00  LOAD==-0.02(0.00)
0

B2_31 "Herdlyn - Balfour 60 kV Line"
 line     33083  33774  "1 " 1     0     # line   from  MDLRVRJT      60.00   (2) to (3)   HRDLNJCT      60.00
 line     33083  33084  "1 " 1     0     # line   from  MDLRVRJT      60.00   (2) to (3)   BXLR_TAP      60.00
 line     33774  33770  "1 " 1     0     # line   from  HRDLNJCT      60.00   (3) to BRKR  HERDLYN      60.00
 line     33774  33782  "1 " 1     0     # line   from  HRDLNJCT      60.00   (3) to (1)   WEST SDE      60.00
 line     33084  33055  "1 " 1     0     # line   from  BXLR_TAP      60.00   (3) to (1)   BIXLER        60.00
 line     33084  33778  "1 " 1     0     # line   from  BXLR_TAP      60.00   (3) to (2)   MDL_RIVR      60.00
 line     33778  33780  "1 " 1     0     # line   from  MDL_RIVR      60.00   (2) to (1)   MCD_ISLE      60.00
 load     33782  "1 "    0              # load         WEST SDE      60.00  LOAD==1.90(0.40)
 load     33782  "E1"    0              # load         WEST SDE      60.00  LOAD==-0.02(0.00)
 load     33055  "1 "    0              # load         BIXLER        60.00  LOAD==2.00(0.97)
 load     33055  "E1"    0              # load         BIXLER        60.00  LOAD==-0.02(0.00)
 load     33778  "1 "    0              # load         MDL_RIVR      60.00  LOAD==4.34(0.62)
 load     33778  "E1"    0              # load         MDL_RIVR      60.00  LOAD==-0.03(0.00)
 load     33780  "1 "    0              # load         MCD_ISLE      60.00  LOAD==6.57(0.94)
 load     33780  "E1"    0              # load         MCD_ISLE      60.00  LOAD==-0.05(0.00)
0

B2_32 "Stanislaus-Melones-Manteca 115 kV Line No. 1"
 line     33500  33509  "1 " 1     0     # line   from  MELNS JA      115.00   (3) to (3)   AVENATP1      115.00
 line     33500  33501  "1 " 1     0     # line   from  MELNS JA      115.00   (3) to (3)   FRGTNTP1      115.00
 line     33500  33932  "1 " 1     0     # line   from  MELNS JA      115.00   (3) to BRKR  MELONES      115.00
 line     33509  33510  "1 " 1     0     # line   from  AVENATP1      115.00   (3) to (1)   AVENA         115.00
 line     33509  33514  "1 " 1     0     # line   from  AVENATP1      115.00   (3) to BRKR  MANTECA       115.00
 line     33501  33502  "1 " 1     0     # line   from  FRGTNTP1      115.00   (3) to (1)   FROGTOWN      115.00
 line     33501  33506  "1 " 1     0     # line   from  FRGTNTP1      115.00   (3) to BRKR  STANISLS      115.00
 load     33510  "1 "    0              # load         AVENA         115.00  LOAD==11.89(1.69)
 load     33510  "E1"    0              # load         AVENA         115.00  LOAD==-0.08(0.00)
 load     33502  "1 "    0              # load         FROGTOWN      115.00  LOAD==7.17(1.02)
 load     33502  "2 "    0              # load         FROGTOWN      115.00  LOAD==11.16(1.59)
 load     33502  "E1"    0              # load         FROGTOWN      115.00  LOAD==-0.03(0.00)
 load     33502  "E2"    0              # load         FROGTOWN      115.00  LOAD==-0.05(0.00)
 line  33511 33510  "1 "  1  1      # Switches in Avenan SW 145 to transfer load
 load  33510        "1 "     1      # Restores Load at Avena
 line   33503 33502  "1 "  1  1      #Switches in Frogtown Sw 145 to transfer load
 load   33502        "1 "     1      #Restore load at Frogtown Bk 1
 load   33502        "2 "     1      #Restore load at Frogtown Bk 2
0

B2_33 "Stanislaus - Melones Sw 115 kV Line"
 line     33503  33936  "1 " 1     0     # line   from  FRGTNTP2      115.00   (2) to (3)   MELNS JB      115.00
 line     33503  33504  "1 " 1     0     # line   from  FRGTNTP2      115.00   (2) to (2)   CATARACT      115.00
 line     33936  33932  "1 " 1     0     # line   from  MELNS JB      115.00   (3) to BRKR  MELONES      115.00
 line     33936  33947  "1 " 1     0     # line   from  MELNS JB      115.00   (3) to BRKR  RIVRBKJT      115.00
 line     33504  33506  "1 " 1     0     # line   from  CATARACT      115.00   (2) to BRKR  STANISLS      115.00
0

B2_34 "Stanislaus - Manteca 115 kV Line No. 2"
 line     33506  33948  "1 " 1     0     # line   from  STANISLS      115.00  BRKR to (2)   RVRBK J2      115.00
 line     33948  33953  "1 " 1     0     # line   from  RVRBK J2      115.00   (2) to (2)   VLYHMTP2      115.00
 line     33953  33511  "1 " 1     0     # line   from  VLYHMTP2      115.00   (2) to (2)   AVENATP2      115.00
 line     33511  33514  "1 " 1     0     # line   from  AVENATP2      115.00   (2) to BRKR  MANTECA       115.00
0

B2_35 "Tesla - Kasson - Manteca 115 kV Line"
 line     33514  33526  "1 " 1     0     # line   from  MANTECA       115.00  BRKR to (3)   KSSN-JC1      115.00
 line     33526  33528  "1 " 1     0     # line   from  KSSN-JC1      115.00   (3) to BRKR  KASSON        115.00
 line     33526  33533  "1 " 1     0     # line   from  KSSN-JC1      115.00   (3) to (2)   OWENSTP2      115.00
 line     33533  33549  "2 " 1     0     # line   from  OWENSTP2      115.00   (2) to BRKR  SCHULTE        115.00
0

B2_36 "Tesla - Salado - Manteca 115 kV Line"
 line     33514  33970  "1 " 1     0     # line   from  MANTECA       115.00  BRKR to (3)   INGRM C.      115.00
 line     33970  33959  "1 " 1     0     # line   from  INGRM C.      115.00   (3) to (2)   TCHRT_T2      115.00
 line     33970  33965  "1 " 1     0     # line   from  INGRM C.      115.00   (3) to (2)   SALADO J      115.00
 line     33959  33540  "1 " 1     0     # line   from  TCHRT_T2      115.00   (2) to BRKR  TESLA         115.00
 line     33965  33964  "1 " 1     0     # line   from  SALADO J      115.00   (2) to BRKR  SALADO        115.00
 load     33970  "1 "    0              # load         INGRM C.      115.00  LOAD==1.91(0.93)
 load     33970  "E1"    0              # load         INGRM C.      115.00  LOAD==-0.03(0.00)
0
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APPENDIX B – CAISO CATEGORY B CONTINGENCY LIST

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B2_37 "Riverbank Jct - Manteca 115 kV Line"
 line     33516  33514  "1 " 1     0     # line   from  RPN JNCN     115.00   (2) to BRKR  MANTECA     115.00
 line     33516  33520  "1 " 1     0     # line   from  RPN JNCN     115.00   (2) to BRKR  RIPON       115.00
0

B2_90 "Ripon - Riverbank Jct 115 kV Line"
 line     33517  33520  "1 " 1     0     # line   from  RPNJN2      115.00   (2) to BRKR  RIPON       115.00
 line     33517  33951  "1 " 1     0     # line   from  RPNJN2      115.00   (2) to (3)   VLYHMTP1    115.00
 line     33951  33947  "1 " 1     0     # line   from  VLYHMTP1    115.00   (3) to BRKR  RIVRBKJT    115.00
 line     33951  33952  "1 " 1     0     # line   from  VLYHMTP1    115.00   (3) to (1)   VALLY HM    115.00
 load     33952  "1 "    0             # load         VALLY HM     115.00  LOAD==3.86(0.55)
 load     33952  "E1"    0             # load         VALLY HM     115.00  LOAD==-0.02(0.00)
0

B2_38 "Manteca - Vierra 115 kV Line"
 line     33518  33514  "1 " 1     0     # line   from  VIERRA      115.00  BRKR to BRKR  MANTECA     115.00
0

B2_39 "Vierra - Tracy - Kasson 115 kV Line"
 line     33518  33522  "1 " 1     0     # line   from  VIERRA      115.00  BRKR to (3)   CROSRDJT    115.00
 line     33522  33524  "1 " 1     0     # line   from  CROSRDJT    115.00   (3) to (1)   CL AMMNA    115.00
 line     33522  33530  "1 " 1     0     # line   from  CROSRDJT    115.00   (3) to (3)   KSSN-JC2    115.00
 line     33530  33528  "1 " 1     0     # line   from  KSSN-JC2    115.00   (3) to BRKR  KASSON      115.00
 line     33530  33550  "1 " 1     0     # line   from  KSSN-JC2    115.00   (3) to (2)   HJ HEINZ    115.00
 line     33550  33548  "1 " 1     0     # line   from  HJ HEINZ    115.00   (2) to BRKR  TRACY       115.00
 load     33524  "1 "    0             # load         CL AMMNA     115.00  LOAD==1.41(1.02)
 load     33524  "E1"    0             # load         CL AMMNA     115.00  LOAD==-0.02(0.00)
0

B2_40 "Lammers - Kasson 115 kV Line"
 line     33528  33531  "1 " 1     0     # line   from  KASSON      115.00  BRKR to (3)   OWENSTP1    115.00
 line     33531  33529  "1 " 1     0     # line   from  OWENSTP1    115.00   (3) to BRKR  LAMMERS     115.00
 line     33531  33532  "1 " 1     0     # line   from  OWENSTP1    115.00   (3) to (1)   OI GLASS    115.00
 load     33532  "1 "    0             # load         OI GLASS     115.00  LOAD==11.09(6.87)
 load     33532  "E1"    0             # load         OI GLASS     115.00  LOAD==-0.10(0.00)
0

B2_41 "Tesla - Schulte 115 kV Line No. 2"
 line     33535  33549  "2 " 1     0     # line   from  SFWY_TP2    115.00   (2) to BRKR  SCHULTE     115.00
 line     33535  33543  "1 " 1     0     # line   from  SFWY_TP2    115.00   (2) to (3)   AEC_TP2     115.00
 line     33543  33540  "1 " 1     0     # line   from  AEC_TP2     115.00   (3) to BRKR  TESLA       115.00
 line     33543  33545  "1 " 1     0     # line   from  AEC_TP2     115.00   (3) to (2)   AEC_JCT     115.00
 line     33545  33547  "1 " 1     0     # line   from  AEC_JCT     115.00   (2) to (1)   AEC_300     115.00
 load     33547  "1 "    0             # load         AEC_300      115.00  LOAD==3.00(0.68)
 load     33547  "E1"    0             # load         AEC_300      115.00  LOAD==-0.03(0.00)
0

B2_42 "Tesla - Schulte 115 kV Line No. 1"
 line     33537  33534  "1 " 1     0     # line   from  SFWY_TP1    115.00   (3) to (1)   SAFEWAY     115.00
 line     33537  33549  "1 " 1     0     # line   from  SFWY_TP1    115.00   (3) to BRKR  SCHULTE     115.00
 line     33537  33541  "1 " 1     0     # line   from  SFWY_TP1    115.00   (3) to (2)   AEC_TP1     115.00
 line     33541  33540  "1 " 1     0     # line   from  AEC_TP1     115.00   (2) to BRKR  TESLA       115.00
 load     33534  "1 "    0             # load         SAFEWAY      115.00  LOAD==3.86(1.98)
 load     33534  "E1"    0             # load         SAFEWAY      115.00  LOAD==-0.07(0.00)
0

B2_43 "Tesla - Tracy 115 kV Line"
 line     33540  33544  "1 " 1     0     # line   from  TESLA       115.00  BRKR to (2)   ELLS GTY    115.00
 line     33544  33546  "1 " 1     0     # line   from  ELLS GTY     115.00   (2) to (2)   TRACY JC    115.00
 line     33546  33542  "1 " 1     0     # line   from  TRACY JC     115.00   (2) to (2)   LEPRINO     115.00
 line     33542  33548  "1 " 1     0     # line   from  LEPRINO      115.00   (2) to BRKR  TRACY       115.00
 load     33544  "1 "    0             # load         ELLS GTY     115.00  LOAD==3.44(1.76)
 load     33544  "E1"    0             # load         ELLS GTY     115.00  LOAD==-0.03(0.00)
 load     33542  "1 "    0             # load         LEPRINO      115.00  LOAD==3.92(2.53)
 load     33542  "E1"    0             # load         LEPRINO      115.00  LOAD==-0.06(0.00)
0

B2_44 "Tesla - Vierra 115 kV Line"
 line     33540  33568  "1 " 1     0     # line   from  TESLA       115.00  BRKR to (3)   TH.E.DV.    115.00
 line     33568  33570  "1 " 1     0     # line   from  TH.E.DV.    115.00   (3) to (3)   SPC JCT.    115.00
 tran     33568  33806  "1 "       0     # tran   from  TH.E.DV.    115.00   (3) to (1)   TH.E.DV.     13.80
 line     33570  33572  "1 " 1     0     # line   from  SPC JCT.    115.00   (3) to (2)   SP CMPNY    115.00
 line     33570  33956  "1 " 1     0     # line   from  SPC JCT.    115.00   (3) to (2)   SJ COGEN    115.00
 tran     33572  33810  "1 "       0     # tran   from  SP CMPNY    115.00   (2) to (1)   SP CMPNY     13.80
 tran     33956  33808  "1 "       0     # tran   from  SJ COGEN    115.00   (2) to (1)   SJ COGEN     13.80
 gen      33806  "1 "    0             # gen          TH.E.DV.      13.80  GEN ==18.53(6.00)
 gen      33810  "1 "    0             # gen          SP CMPNY      13.80  GEN ==34.37(2.77)
 gen      33808  "1 "    0             # gen          SJ COGEN      13.80  GEN ==48.00(6.85)
0
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B2_45 "Lawrence Lab 115 kV Tap #1"
 line     33540  33574  "1 " 1     0     # line   from  TESLA       115.00  BRKR to (2)   LLNL TAP     115.00
 line     33574  37649  "1 " 1     0     # line   from  LLNL TAP    115.00   (2) to BRKR  LLNLAB       115.00
0

B2_46 "Tesla - Trust 115 kV Line"
 line     33540  33576  "1 " 1     0     # line   from  TESLA       115.00  BRKR to (3)   USWP-PAT     115.00
 line     33576  33578  "1 " 1     0     # line   from  USWP-PAT    115.00   (3) to (2)   FAYETTE      115.00
 tran     33576  33842  "1 "       0     # tran   from  USWP-PAT    115.00   (3) to (1)   PATTERSN       9.11
 line     33578  33580  "1 " 1     0     # line   from  FAYETTE     115.00   (2) to (2)   ALTENRGY     115.00
 tran     33580  33834  "1 "       0     # tran   from  ALTENRGY    115.00   (2) to (1)   KALINA         9.11
 gen      33842  "3 "    0             # gen          PATTERSN      9.11  GEN ==19.34(0.00)
 svd      33576  "v "    0             # svd          USWP-PAT    115.00
0

B2_47 "Tesla - Salado 115 kV Line No. 1"
 line     33540  33961  "1 " 1     0     # line   from  TESLA       115.00  BRKR to (3)   TCHRT_T1     115.00
 line     33961  33960  "1 " 1     0     # line   from  TCHRT_T1    115.00   (3) to (2)   MDSTO_CN     115.00
 line     33961  33963  "1 " 1     0     # line   from  TCHRT_T1    115.00   (3) to (2)   TCHRTJCT     115.00
 line     33960  33962  "1 " 1     0     # line   from  MDSTO_CN    115.00   (2) to (3)   SALDO TP     115.00
 line     33962  33964  "1 " 1     0     # line   from  SALDO TP    115.00   (3) to BRKR  SALADO       115.00
 line     33962  33967  "1 " 1     0     # line   from  SALDO TP    115.00   (3) to (2)   MILER TP     115.00
 line     33967  33966  "1 " 1     0     # line   from  MILER TP    115.00   (2) to (1)   MILLER       115.00
 line     33963  33569  "1 " 1     0     # line   from  TCHRTJCT    115.00   (2) to (2)   GRANITE      115.00
 line     33569  33968  "1 " 1     0     # line   from  GRANITE     115.00   (2) to (1)   TEICHERT     115.00
 load     33966  "1 "    0             # load         MILLER       115.00  LOAD==1.82(0.88)
 load     33966  "E1"    0             # load         MILLER       115.00  LOAD==-0.03(0.00)
 load     33569  "1 "    0             # load         GRANITE      115.00  LOAD==4.81(1.10)
 load     33569  "E1"    0             # load         GRANITE      115.00  LOAD==-0.06(0.00)
 load     33968  "1 "    0             # load         TEICHERT     115.00  LOAD==7.31(6.45)
 load     33968  "E1"    0             # load         TEICHERT     115.00  LOAD==-0.06(0.00)
0

B2_48 "Schulte - Lammers 115 kV Line"
 line     33549  33529  "1 " 1     0     # line   from  SCHULTE     115.00  BRKR to BRKR  LAMMERS      115.00
0

B2_49 "GWF Tracy - Schulte 115 kV Line"
 line     33551  33549  "1 " 1     0     # line   from  GWFTRACY    115.00  BRKR to BRKR  SCHULTE      115.00
0

B2_50 "Stockton 'A' - Lockeford - Bellota 115 kV Line No. 2"
 line     33552  33553  "1 " 1     0     # line   from  STCKTNJB    115.00   (2) to BRKR  STKTON B     115.00
 line     33552  33590  "1 " 1     0     # line   from  STCKTNJB    115.00   (2) to (2)   KYOHOTAP     115.00
 line     33590  33558  "1 " 1     0     # line   from  KYOHOTAP    115.00   (2) to (3)   LCKFRDJB     115.00
 line     33558  33562  "1 " 1     0     # line   from  LCKFRDJB    115.00   (3) to BRKR  BELLOTA      115.00
 line     33558  33564  "1 " 1     0     # line   from  LCKFRDJB    115.00   (3) to BRKR  LOCKFORD     115.00
 load     33553  "3 "    0             # load         STKTON B     115.00  LOAD==25.86(3.68)
 load     33553  "E3"    0             # load         STKTON B     115.00  LOAD==-0.16(0.00)
 line  33555 33553  "1 "  1  1      # Switches in Stockton 'A' SW 177 to transfer load
 load  33553        "3 "     1      # Restore Load at Stockton 'A' Bk  3
0

B2_51 "Stockton 'A'-Lockeford-Bellota 115 kV Line No. 1"
 line     33556  33555  "1 " 1     0     # line   from  STN COGN     115.00   (3) to BRKR  STKTON A     115.00
 line     33556  33560  "1 " 1     0     # line   from  STN COGN     115.00   (3) to (2)   LCKFRDJA     115.00
 line     33556  33958  "1 " 1     0     # line   from  STN COGN     115.00   (3) to (2)   CPC STCN     115.00
 line     33560  33562  "1 " 1     0     # line   from  LCKFRDJA     115.00   (2) to BRKR  BELLOTA      115.00
 tran     33958  33814  "1 "       0     # tran   from  CPC STCN     115.00   (2) to (1)   CPC STCN      12.47
 load     33555  "4 "    0             # load         STKTON A     115.00  LOAD==22.53(3.21)
 load     33555  "5 "    0             # load         STKTON A     115.00  LOAD==19.76(2.81)
 load     33555  "E4"    0             # load         STKTON A     115.00  LOAD==-0.12(0.00)
 load     33555  "E5"    0             # load         STKTON A     115.00  LOAD==-0.12(0.00)
 load     33814  "SG"    0             # load         CPC STCN      12.47  LOAD==5.06(1.15)
 gen      33814  "1 "    0             # gen          CPC STCN      12.47  GEN ==41.60(5.07)
 line  33555 33553  "1 "  1  1      # Switches in Stockton 'A' SW 177 to transfer load
 load  33555        "4 "     1      # Restore Load at Stockton 'A' Bk 4
 load  33555        "5 "     1      # Restore Load at Stockton 'A' Bk 5
0

B2_52 "Gold Hill-Bellota-Lockeford 115 kV Line"
 line     33561  33562  "1 " 1     0     # line   from  BLLTAJCT    115.00   (3) to BRKR  BELLOTA      115.00
 line     33561  33564  "1 " 1     0     # line   from  BLLTAJCT    115.00   (3) to BRKR  LOCKFORD     115.00
 line     33561  33565  "1 " 1     0     # line   from  BLLTAJCT    115.00   (3) to (2)   CMNCHETP     115.00
 line     33565  33566  "1 " 1     0     # line   from  CMNCHETP    115.00   (2) to BRKR  CAMANCHE     115.00
0

B2_53 "Bellota - Riverbank 115 kV Line"
 line     33562  33946  "1 " 1     0     # line   from  BELLOTA     115.00  BRKR to (2)   RVRBK J1     115.00
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 line     33946  33944  "1 " 1     0     # line   from  RVRBK J1     115.00   (2) to BRKR  RVRBANK     115.00
0

B2_54 "Bellota-Riverbank-Melones 115 kV Line"
 line     33562  33950  "1 " 1     0     # line   from  BELLOTA     115.00  BRKR to (3)   RVRBK TP    115.00
 line     33950  33934  "1 " 1     0     # line   from  RVRBK TP    115.00   (3) to (3)   TULLOCH     115.00
 line     33950  33944  "1 " 1     0     # line   from  RVRBK TP    115.00   (3) to BRKR  RVRBANK     115.00
 line     33934  33932  "1 " 1     0     # line   from  TULLOCH     115.00   (3) to BRKR  MELONES     115.00
 tran     33934  34076  "1 "       0     # tran   from  TULLOCH     115.00   (3) to (1)   TULLOCH       6.90
 gen      34076  "1 "    0             # gen          TULLOCH       6.90  GEN ==8.64(1.00)
 gen      34076  "2 "    0             # gen          TULLOCH       6.90  GEN ==8.64(1.00)
0

B2_55 "Tiger Creek - Salt Springs 115 kV Line"
 line     33582  39601  "1 " 1     0     # line   from  SLT SPRG     115.00  BRKR to (3)   KMPUDTAP    115.00
 line     39601  33584  "1 " 1     0     # line   from  KMPUDTAP    115.00   (3) to BRKR  TIGR CRK     115.00
 line     39601  39602  "1 " 1     0     # line   from  KMPUDTAP    115.00   (3) to BRKR  KMPUDSUB    115.00
0

B2_56 "Stockton 'A' 60 kV Line No. 1"
 line     33602  33670  "1 " 1     0     # line   from  NEWARKS      60.00   (2) to BRKR  STCKTN A     60.00
 line     33602  33672  "1 " 1     0     # line   from  NEWARKS      60.00   (2) to (2)   CHRTRWYS     60.00
 line     33672  33673  "1 " 1     0     # line   from  CHRTRWYS     60.00   (2) to (2)   CAL CEDA     60.00
 line     33673  33688  "1 " 1     0     # line   from  CAL CEDA     60.00   (2) to (3)   ROB-LRNR     60.00
 line     33688  33687  "1 " 1     0     # line   from  ROB-LRNR     60.00   (3) to (2)   STKTN WW     60.00
 line     33688  33696  "1 " 1     0     # line   from  ROB-LRNR     60.00   (3) to (3)   COG.NTNL     60.00
 line     33687  33689  "1 " 1     0     # line   from  STKTN WW     60.00   (2) to (1)   LEARNER      60.00
 line     33696  33690  "1 " 1     0     # line   from  COG.NTNL     60.00   (3) to (3)   ROGH-RDY     60.00
 line     33696  33697  "1 " 1     0     # line   from  COG.NTNL     60.00   (3) to (1)   PAC_ETH      60.00
 line     33690  33691  "1 " 1     0     # line   from  ROGH-RDY     60.00   (3) to (1)   P.STCKTN     60.00
 line     33690  33692  "1 " 1     0     # line   from  ROGH-RDY     60.00   (3) to (2)   CHANNEL      60.00
 line     33692  33694  "1 " 1     0     # line   from  CHANNEL      60.00   (2) to (1)   CHNNL JT     60.00
 load     33673  "1 "    0             # load         CAL CEDA      60.00  LOAD==1.34(1.11)
 load     33673  "E1"    0             # load         CAL CEDA      60.00  LOAD==-0.01(0.00)
 load     33687  "1 "    0             # load         STKTN WW      60.00  LOAD==3.56(0.89)
 load     33687  "E1"    0             # load         STKTN WW      60.00  LOAD==-0.03(0.00)
 load     33690  "1 "    0             # load         ROGH-RDY      60.00  LOAD==9.60(1.37)
 load     33690  "E1"    0             # load         ROGH-RDY      60.00  LOAD==-0.05(0.00)
 load     33697  "1 "    0             # load         PAC_ETH       60.00  LOAD==5.58(1.27)
 load     33697  "E1"    0             # load         PAC_ETH       60.00  LOAD==-0.08(0.00)
 load     33691  "1 "    0             # load         P.STCKTN      60.00  LOAD==9.00(1.28)
 load     33691  "E1"    0             # load         P.STCKTN      60.00  LOAD==-0.08(0.00)
 load     33692  "1 "    0             # load         CHANNEL       60.00  LOAD==9.31(1.33)
 load     33692  "E1"    0             # load         CHANNEL       60.00  LOAD==-0.04(0.00)
 gen      33687  "1 "    0             # gen          STKTN WW      60.00  GEN ==1.50(0.15)
0

B2_57 "West Point - Valley Springs 60 kV Line"
 line     33604  33606  "1 " 1     0     # line   from  WEST PNT     60.00   (2) to (3)   P.GRVEJ.     60.00
 tran     33604  33820  "1 "       0     # tran   from  WEST PNT     60.00   (2) to (1)   WEST PNT     11.50
 line     33606  33607  "1 " 1     0     # line   from  P.GRVEJ.     60.00   (3) to (2)   ELECTRAJ     60.00
 line     33606  33608  "1 " 1     0     # line   from  P.GRVEJ.     60.00   (3) to (1)   PNE GRVE     60.00
 line     33607  33610  "1 " 1     0     # line   from  ELECTRAJ     60.00   (2) to BRKR  VLLY SPS     60.00
 load     33604  "1 "    0             # load         WEST PNT      60.00  LOAD==4.53(0.65)
 load     33604  "3 "    0             # load         WEST PNT      60.00  LOAD==4.22(0.60)
 load     33604  "E1"    0             # load         WEST PNT      60.00  LOAD==-0.02(0.00)
 load     33604  "E3"    0             # load         WEST PNT      60.00  LOAD==-0.02(0.00)
 load     33607  "1 "    0             # load         ELECTRAJ      60.00  LOAD==9.88(1.41)
 load     33607  "E1"    0             # load         ELECTRAJ      60.00  LOAD==-0.05(0.00)
 load     33608  "1 "    0             # load         PNE GRVE      60.00  LOAD==7.11(1.01)
 load     33608  "2 "    0             # load         PNE GRVE      60.00  LOAD==8.65(1.23)
 load     33608  "E1"    0             # load         PNE GRVE      60.00  LOAD==-0.05(0.00)
 load     33608  "E2"    0             # load         PNE GRVE      60.00  LOAD==-0.05(0.00)
 gen      33820  "1 "    0             # gen          WEST PNT      11.50  GEN ==13.60(5.48)
0

B2_58 "Valley Springs - Calaveras Cement 60 kV Line"
 line     33610  33612  "1 " 1     0     # line   from  VLLY SPS     60.00  BRKR to (2)   N BRANCH     60.00
 line     33612  33614  "1 " 1     0     # line   from  N BRANCH     60.00   (2) to BRKR  CAL CMNT     60.00
 load     33612  "1 "    0             # load         N BRANCH      60.00  LOAD==4.95(0.71)
 load     33612  "E1"    0             # load         N BRANCH      60.00  LOAD==-0.02(0.00)
 load     33614  "1 "    0             # load         CAL CMNT      60.00  LOAD==9.99(1.42)
 load     33614  "E1"    0             # load         CAL CMNT      60.00  LOAD==-0.05(0.00)
0

B2_59 "Valley Springs - Martell 60 kV Line No. 1"
 line     33610  33619  "1 " 1     0     # line   from  VLLY SPS     60.00  BRKR to (3)   AMFOR_SW     60.00
 line     33619  33616  "1 " 1     0     # line   from  AMFOR_SW     60.00   (3) to BRKR  MARTELL      60.00
 line     33619  33620  "1 " 1     0     # line   from  AMFOR_SW     60.00   (3) to (1)   AM FORST     60.00
 load     33616  "1 "    0             # load         MARTELL       60.00  LOAD==16.28(2.32)
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 load     33616  "E1"    0              # load         MARTELL      60.00  LOAD==-0.08(0.00)
 load     33620  "1 "    0              # load         AM FORST     60.00  LOAD==1.95(1.56)
 load     33620  "E1"    0              # load         AM FORST     60.00  LOAD==-0.02(0.00)
0

B2_60 "Valley Springs No. 2 60 kV Line"
 line     33610  33629  "2 " 1    0     # line   from  VLLY SPS     60.00  BRKR to (3)   PRDEJCT      60.00
 line     33629  33630  "2 " 1    0     # line   from  PRDEJCT      60.00   (3) to (2)   PARDEE A     60.00
 line     33629  33631  "2 " 1    0     # line   from  PRDEJCT      60.00   (3) to (1)   VSLDSW87     60.00
 tran     33630  33848  "1 "      0     # tran   from  PARDEE A     60.00   (2) to (1)   PARDE 2       7.20
0

B2_61 "Valley Springs - Martell 60 kV Line No. 2"
 line     33610  33634  "1 " 1    0     # line   from  VLLY SPS     60.00  BRKR to (3)   PRDESWS      60.00
 line     33634  33626  "1 " 1    0     # line   from  PRDESWS      60.00   (3) to (3)   TAPP1009     60.00
 tran     33634  33846  "1 "      0     # tran   from  PRDESWS      60.00   (3) to (1)   PRDE 1-3      7.20
 line     33626  33622  "1 " 1    0     # line   from  TAPP1009     60.00   (3) to (2)   CLAY         60.00
 line     33626  33628  "1 " 1    0     # line   from  TAPP1009     60.00   (3) to (2)   RPSP1009     60.00
 line     33622  33623  "1 " 1    0     # line   from  CLAY         60.00   (2) to (3)   INE_TP       60.00
 line     33623  33617  "1 " 1    0     # line   from  INE_TP       60.00   (3) to (1)   MARTELTP     60.00
 line     33623  33624  "1 " 1    0     # line   from  INE_TP       60.00   (3) to (1)   INE PRSN     60.00
 tran     33628  33816  "1 "      0     # tran   from  RPSP1009     60.00   (2) to (1)   RPSP1009     13.80
 load     33622  "1 "    0              # load         CLAY         60.00  LOAD==9.12(1.30)
 load     33622  "2 "    0              # load         CLAY         60.00  LOAD==7.86(1.12)
 load     33622  "E1"    0              # load         CLAY         60.00  LOAD==-0.07(0.00)
 load     33622  "E2"    0              # load         CLAY         60.00  LOAD==-0.03(0.00)
 load     33624  "1 "    0              # load         INE PRSN     60.00  LOAD==7.27(1.04)
 load     33624  "E1"    0              # load         INE PRSN     60.00  LOAD==-0.07(0.00)
 load     33816  "ss"    0              # load         RPSP1009     13.80  LOAD==2.60(1.44)
 gen      33816  "1 "    0              # gen          RPSP1009     13.80  GEN ==18.40(3.71)
0

B2_62 "Valley Springs No. 1 60 kV Line"
 line     33610  33636  "1 " 1    0     # line   from  VLLY SPS     60.00  BRKR to (3)   N.HGN JT     60.00
 line     33636  33638  "1 " 1    0     # line   from  N.HGN JT     60.00   (3) to (2)   N.HOGAN      60.00
 line     33636  33640  "1 " 1    0     # line   from  N.HGN JT     60.00   (3) to (1)   CORRAL       60.00
 tran     33638  38365  "1 "      0     # tran   from  N.HOGAN      60.00   (2) to (1)   N.HGN DM     12.00
 load     33640  "1 "    0              # load         CORRAL       60.00  LOAD==15.66(2.24)
 load     33640  "2 "    0              # load         CORRAL       60.00  LOAD==8.35(1.19)
 load     33640  "E1"    0              # load         CORRAL       60.00  LOAD==-0.07(0.00)
 load     33640  "E2"    0              # load         CORRAL       60.00  LOAD==-0.04(0.00)
 gen      38365  "1 "    0              # gen          N.HGN DM     12.00  GEN ==0.80(-0.60)
 gen      38365  "2 "    0              # gen          N.HGN DM     12.00  GEN ==0.80(-0.33)
0

B2_63 "Weber - Mormon Jct 60 kV Line"
 line     33642  33644  "1 " 1    0     # line   from  LINDEN       60.00   (1) to (2)   MRMN JCT     60.00
 line     33644  33646  "1 " 1    0     # line   from  MRMN JCT     60.00   (2) to (2)   MORMON       60.00
 line     33646  33650  "1 " 1    0     # line   from  MORMON       60.00   (2) to BRKR  WEBER 1     60.00
 load     33642  "1 "    0              # load         LINDEN       60.00  LOAD==13.86(1.97)
 load     33642  "E1"    0              # load         LINDEN       60.00  LOAD==-0.09(0.00)
 load     33646  "1 "    0              # load         MORMON       60.00  LOAD==20.00(2.85)
 load     33646  "E1"    0              # load         MORMON       60.00  LOAD==-0.10(0.00)
 line  33642 33640  "1 "  1  1      # Switches in Linden SW 27 to transfer load
 load  33642        "1 "     1      # Restore Load and Linden
0

B2_64 "Weber 60 kV Line No. 1 (Weber - French Camp)"
 line     33647  33648  "1 " 1    0     # line   from  WEBER016     60.00   (2) to (2)   DANA         60.00
 line     33647  33650  "1 " 1    0     # line   from  WEBER016     60.00   (2) to BRKR  WEBER 1     60.00
 line     33648  33656  "1 " 1    0     # line   from  DANA         60.00   (2) to (2)   CARGILL      60.00
 line     33656  33660  "1 " 1    0     # line   from  CARGILL      60.00   (2) to (2)   JM           60.00
 line     33660  33698  "1 " 1    0     # line   from  JM           60.00   (2) to (2)   FRNCH CP     60.00
 line     33698  33700  "1 " 1    0     # line   from  FRNCH CP     60.00   (2) to (1)   FRNCH CJ     60.00
 load     33648  "1 "    0              # load         DANA         60.00  LOAD==0.20(0.04)
 load     33648  "E1"    0              # load         DANA         60.00  LOAD==-0.03(0.00)
 load     33656  "1 "    0              # load         CARGILL      60.00  LOAD==2.18(2.15)
 load     33656  "E1"    0              # load         CARGILL      60.00  LOAD==-0.02(0.00)
 load     33660  "1 "    0              # load         JM           60.00  LOAD==4.51(1.78)
 load     33660  "E1"    0              # load         JM           60.00  LOAD==-0.03(0.00)
 load     33698  "1 "    0              # load         FRNCH CP     60.00  LOAD==12.55(1.78)
 load     33698  "2 "    0              # load         FRNCH CP     60.00  LOAD==10.44(1.49)
 load     33698  "E1"    0              # load         FRNCH CP     60.00  LOAD==-0.08(0.00)
 load     33698  "E2"    0              # load         FRNCH CP     60.00  LOAD==-0.06(0.00)
0

B2_65 "Stockton 'A' - Weber 60 kV Line No. 1"
 line     33654  33664  "1 " 1    0     # line   from  SNTA FEA     60.00   (3) to (2)   LIPTON       60.00
 line     33654  33670  "1 " 1    0     # line   from  SNTA FEA     60.00   (3) to BRKR  STCKTN A     60.00
 line     33654  33662  "1 " 1    0     # line   from  SNTA FEA     60.00   (3) to BRKR  WEBER 2     60.00
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 line     33664  33666  "1 " 1     0     # line   from  LIPTON        60.00   (2) to (2)   CHEROKEE      60.00
 line     33666  33668  "1 " 1     0     # line   from  CHEROKEE      60.00   (2) to (1)   WATERLOO      60.00
 load     33664  "1 "    0               # load         LIPTON        60.00  LOAD==3.13(2.27)
 load     33664  "E1"    0               # load         LIPTON        60.00  LOAD==-0.05(0.00)
 load     33666  "1 "    0               # load         CHEROKEE      60.00  LOAD==9.41(1.34)
 load     33666  "E1"    0               # load         CHEROKEE      60.00  LOAD==-0.05(0.00)
 load     33668  "2 "    0               # load         WATERLOO      60.00  LOAD==6.66(0.95)
 load     33668  "E2"    0               # load         WATERLOO      60.00  LOAD==-0.05(0.00)
0

B2_66 "Stockton 'A' - Weber 60 kV Line No. 2"
 line     33658  33670  "1 " 1     0     # line   from  SNTA FEB      60.00   (3) to BRKR  STCKTN A      60.00
 line     33658  33678  "1 " 1     0     # line   from  SNTA FEB      60.00   (3) to (2)   MONARCH       60.00
 line     33658  33662  "1 " 1     0     # line   from  SNTA FEB      60.00   (3) to BRKR  WEBER 2      60.00
 line     33678  33684  "1 " 1     0     # line   from  MONARCH       60.00   (2) to (2)   HARDING       60.00
 line     33684  33686  "1 " 1     0     # line   from  HARDING       60.00   (2) to (1)   STCKTNAR      60.00
 load     33678  "2 "    0               # load         MONARCH       60.00  LOAD==4.49(0.64)
 load     33678  "E2"    0               # load         MONARCH       60.00  LOAD==-0.02(0.00)
 load     33684  "1 "    0               # load         HARDING       60.00  LOAD==6.25(0.89)
 load     33684  "2 "    0               # load         HARDING       60.00  LOAD==3.36(0.48)
 load     33684  "E1"    0               # load         HARDING       60.00  LOAD==-0.02(0.00)
 load     33684  "E2"    0               # load         HARDING       60.00  LOAD==-0.02(0.00)
 load     33686  "1 "    0               # load         STCKTNAR      60.00  LOAD==2.80(0.40)
 load     33686  "E1"    0               # load         STCKTNAR      60.00  LOAD==-0.01(0.00)
0

B2_67 "Stockton 'A' - Weber 60 kV Line No. 3"
 line     33662  33674  "1 " 1     0     # line   from  WEBER 2       60.00  BRKR to (4)   HAZLTN J      60.00
 line     33674  33670  "1 " 1     0     # line   from  HAZLTN J      60.00   (4) to BRKR  STCKTN A      60.00
 line     33674  33676  "1 " 1     0     # line   from  HAZLTN J      60.00   (4) to (1)   E.STCKTN      60.00
 line     33674  33681  "1 " 1     0     # line   from  HAZLTN J      60.00   (4) to (2)   N.ST_SW       60.00
 line     33681  33682  "1 " 1     0     # line   from  N.ST_SW       60.00   (2) to (2)   SUMIDEN       60.00
 line     33682  33680  "1 " 1     0     # line   from  SUMIDEN       60.00   (2) to (2)   OAK PARK      60.00
 line     33680  33712  "1 " 1     0     # line   from  OAK PARK      60.00   (2) to (1)   WESTLANE      60.00
 load     33676  "1 "    0               # load         E.STCKTN      60.00  LOAD==5.69(0.81)
 load     33676  "3 "    0               # load         E.STCKTN      60.00  LOAD==11.45(1.63)
 load     33676  "E1"    0               # load         E.STCKTN      60.00  LOAD==-0.02(0.00)
 load     33676  "E3"    0               # load         E.STCKTN      60.00  LOAD==-0.08(0.00)
 load     33682  "1 "    0               # load         SUMIDEN       60.00  LOAD==3.08(2.15)
 load     33682  "E1"    0               # load         SUMIDEN       60.00  LOAD==-0.03(0.00)
 load     33680  "1 "    0               # load         OAK PARK      60.00  LOAD==1.88(0.26)
 load     33680  "E1"    0               # load         OAK PARK      60.00  LOAD==-0.01(0.00)
 load     33712  "1 "    0               # load         WESTLANE      60.00  LOAD==22.49(3.20)
 load     33712  "E1"    0               # load         WESTLANE      60.00  LOAD==-0.07(0.00)
0

B2_68 "Stagg 60 kV Line No. 1"
 line     33693  33704  "1 " 1     0     # line   from  STAGG JT      60.00   (2) to BRKR  STAGG         60.00
 line     33693  33719  "1 " 1     0     # line   from  STAGG JT      60.00   (2) to (3)   TERMNS J      60.00
 line     33719  33720  "1 " 1     0     # line   from  TERMNS J      60.00   (3) to (1)   TERMNOUS      60.00
 line     33719  33721  "1 " 1     0     # line   from  TERMNS J      60.00   (3) to (2)   SEBASTIA      60.00
 line     33721  33722  "1 " 1     0     # line   from  SEBASTIA      60.00   (2) to (2)   NW HPE J      60.00
 line     33722  33723  "1 " 1     0     # line   from  NW HPE J      60.00   (2) to (1)   NEW HOPE      60.00
 load     33720  "1 "    0               # load         TERMNOUS      60.00  LOAD==3.67(0.53)
 load     33720  "E1"    0               # load         TERMNOUS      60.00  LOAD==-0.02(0.00)
 load     33721  "1 "    0               # load         SEBASTIA      60.00  LOAD==2.77(2.08)
 load     33721  "E1"    0               # load         SEBASTIA      60.00  LOAD==-0.03(0.00)
 load     33723  "1 "    0               # load         NEW HOPE      60.00  LOAD==4.11(0.59)
 load     33723  "E1"    0               # load         NEW HOPE      60.00  LOAD==-0.02(0.00)
0

B2_69 "Manteca - Louise 60 kV Line"
 line     33703  33702  "1 " 1     0     # line   from  LOUISJCT      60.00   (3) to (1)   GRONMYER      60.00
 line     33703  33746  "1 " 1     0     # line   from  LOUISJCT      60.00   (3) to BRKR  LOUISE        60.00
 line     33703  33742  "1 " 1     0     # line   from  LOUISJCT      60.00   (3) to BRKR  MANTECA       60.00
 load     33702  "1 "    0               # load         GRONMYER      60.00  LOAD==4.20(0.96)
 load     33702  "E1"    0               # load         GRONMYER      60.00  LOAD==-0.04(0.00)
0

B2_70 "Stagg - Country Club 60 kV Line No. 1"
 line     33704  33706  "1 " 1     0     # line   from  STAGG         60.00  BRKR to BRKR  CNTRY CB      60.00
0

B2_71 "Stagg - Country Club 60 kV Line No. 2"
 line     33704  33706  "2 " 1     0     # line   from  STAGG         60.00  BRKR to BRKR  CNTRY CB      60.00
0

B2_72 "Stagg - Hammer 60 kV Line No. 1"
 line     33704  33714  "1 " 1     0     # line   from  STAGG         60.00  BRKR to BRKR  HAMMER        60.00
0
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B2_73 "Hammer - Country Club 60 kV"
 line     33706  33708  "1 " 1     0     # line   from  CNTRY CB      60.00  BRKR to (2)   UOP          60.00
 line     33708  33710  "1 " 1     0     # line   from  UOP          60.00   (2) to (2)   WSTLNESW     60.00
 line     33710  33716  "1 " 1     0     # line   from  WSTLNESW     60.00   (2) to (3)   HMMR JCT     60.00
 line     33716  33714  "1 " 1     0     # line   from  HMMR JCT     60.00   (3) to BRKR  HAMMER      60.00
 line     33716  33717  "1 " 1     0     # line   from  HMMR JCT     60.00   (3) to (3)   MORADAJT     60.00
 line     33717  33718  "1 " 1     0     # line   from  MORADAJT     60.00   (3) to (1)   METTLER      60.00
 line     33717  33740  "1 " 1     0     # line   from  MORADAJT     60.00   (3) to BRKR  MSHR 60V     60.00
 load     33708  "1 "    0             # load         UOP          60.00  LOAD==6.39(4.46)
 load     33708  "E1"    0             # load         UOP          60.00  LOAD==-0.06(0.00)
 load     33718  "3 "    0             # load         METTLER      60.00  LOAD==8.21(1.17)
 load     33718  "E3"    0             # load         METTLER      60.00  LOAD==-0.03(0.00)
 load     33740  "1 "    0             # load         MSHR 60V     60.00  LOAD==16.98(2.42)
 load     33740  "2 "    0             # load         MSHR 60V     60.00  LOAD==11.29(1.61)
 load     33740  "3 "    0             # load         MSHR 60V     60.00  LOAD==23.70(3.37)
 load     33740  "E1"    0             # load         MSHR 60V     60.00  LOAD==-0.11(0.00)
 load     33740  "E2"    0             # load         MSHR 60V     60.00  LOAD==-0.14(0.00)
 line  33738 33740  "1"   1  1      # Switch in Mosher SW 67 to transfer load
 load  33740        "1"      1      # Restore Mosher Bank 1 load
 load  33740        "2"      1      # Restore Mosher Bank 2 load
 load  33740        "3"      1      # Restore Mosher Bank 3 load
0

B2_74 "Lockeford - Lodi 60 kV Line No. 2"
 line     33724  33726  "1 " 1     0     # line   from  LOCKEFRD     60.00  BRKR to (2)   VICTOR       60.00
 line     33726  33731  "1 " 1     0     # line   from  VICTOR       60.00   (2) to (2)   WODBRG J     60.00
 line     33731  33735  "1 " 1     0     # line   from  WODBRG J     60.00   (2) to (2)   INDSTR J     60.00
 line     33735  38060  "1 " 1     0     # line   from  INDSTR J     60.00   (2) to BRKR  INDUSTRL     60.00
 load     33726  "1 "    0             # load         VICTOR       60.00  LOAD==12.35(1.76)
 load     33726  "E1"    0             # load         VICTOR       60.00  LOAD==-0.04(0.00)
 load     33726  "E2"    0             # load         VICTOR       60.00  LOAD==-0.01(0.00)
0

B2_75 "Lockeford - Lodi 60 kV Line No. 3"
 line     33724  33736  "1 " 1     0     # line   from  LOCKEFRD     60.00  BRKR to (2)   LODI JCT     60.00
 line     33736  33729  "1 " 1     0     # line   from  LODI JCT     60.00   (2) to BRKR  LODI AUX     60.00
0

B2_76 "Lockeford No. 1 60 kV Line"
 line     33724  33739  "1 " 1     0     # line   from  LOCKEFRD     60.00  BRKR to (2)   HNYLNJCT     60.00
 line     33739  33738  "1 " 1     0     # line   from  HNYLNJCT     60.00   (2) to (1)   WATRLJCT     60.00
0

B2_77 "Lockeford - Industrial 60 kV Line"
 line     33724  38060  "1 " 1     0     # line   from  LOCKEFRD     60.00  BRKR to BRKR  INDUSTRL     60.00
0

B2_78 "Lockeford-Lodi 60 kV Line No. 2 (Woodbridge Tap)"
 line     33737  33727  "1 " 1     0     # line   from  WINERY J     60.00   (2) to (1)   MONDAVI      60.00
 line     33737  33728  "1 " 1     0     # line   from  WINERY J     60.00   (2) to BRKR  LODI        60.00
 load     33727  "1 "    0             # load         MONDAVI      60.00  LOAD==2.41(2.00)
 load     33727  "E1"    0             # load         MONDAVI      60.00  LOAD==-0.02(0.00)
0

B2_79 "Manteca 60 kV Line No. 1"
 line     33743  33742  "1 " 1     0     # line   from  LEE_JCT      60.00   (2) to BRKR  MANTECA      60.00
 line     33743  33766  "1 " 1     0     # line   from  LEE_JCT      60.00   (2) to (2)   MNTCA JT     60.00
 line     33766  33768  "1 " 1     0     # line   from  MNTCA JT     60.00   (2) to (2)   BNTA CRB     60.00
 line     33768  34000  "1 " 1     0     # line   from  BNTA CRB     60.00   (2) to (1)   WESTLEY      60.00
 load     33768  "1 "    0             # load         BNTA CRB     60.00  LOAD==3.34(0.76)
 load     33768  "E1"    0             # load         BNTA CRB     60.00  LOAD==-0.03(0.00)
 load     34000  "1 "    0             # load         WESTLEY      60.00  LOAD==7.80(1.11)
 load     34000  "2 "    0             # load         WESTLEY      60.00  LOAD==5.70(0.82)
 load     34000  "E1"    0             # load         WESTLEY      60.00  LOAD==-0.07(0.00)
 load     34000  "E2"    0             # load         WESTLEY      60.00  LOAD==-0.02(0.00)
 line  33742 33752  "1 "  1  0      # Must include Manteca - Lanthrop Jct in this outage
0

B2_80 "Kasson - Louise 60 kV Line"
 line     33746  33748  "1 " 1     0     # line   from  LOUISE       60.00  BRKR to (2)   MSSDLESW     60.00
 line     33748  33750  "1 " 1     0     # line   from  MSSDLESW     60.00   (2) to (2)   CALVO        60.00
 line     33750  33756  "1 " 1     0     # line   from  CALVO        60.00   (2) to BRKR  KASSON       60.00
 load     33750  "1 "    0             # load         CALVO        60.00  LOAD==1.70(1.01)
 load     33750  "E1"    0             # load         CALVO        60.00  LOAD==-0.01(0.00)
0

B2_81 "Kasson - Banta 60 kV Line No. 1"
 line     33756  33758  "1 " 1     0     # line   from  KASSON       60.00  BRKR to BRKR  BANTA        60.00
 load     33758  "1 "    0             # load         BANTA        60.00  LOAD==5.94(0.85)
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 load     33758  "E1"    0              # load          BANTA          60.00  LOAD==-0.04(0.00)
0

B2_82 "Kasson 60 kV Line No. 2"
 line     33756  33760  "1 " 1     0     # line   from  KASSON         60.00  BRKR to (2)    BNTA JCT      60.00
 line     33760  33764  "1 " 1     0     # line   from  BNTA JCT       60.00   (2) to (1)    CARBONA       60.00
 load     33764  "1 "    0             # load          CARBONA        60.00  LOAD==23.36(3.33)
 load     33764  "2 "    0             # load          CARBONA        60.00  LOAD==6.07(0.87)
 load     33764  "E1"    0             # load          CARBONA        60.00  LOAD==-0.11(0.00)
 load     33764  "E2"    0             # load          CARBONA        60.00  LOAD==-0.02(0.00)
0

B2_83 "Kasson - Carbona 60 kV Line"
 line     33756  33762  "1 " 1     0     # line   from  KASSON         60.00  BRKR to (2)    LYOTH-SP      60.00
 line     33762  33763  "1 " 1     0     # line   from  LYOTH-SP       60.00   (2) to (1)    CRBNA JC      60.00
 load     33762  "1 "    0             # load          LYOTH-SP       60.00  LOAD==3.90(0.89)
 load     33762  "E1"    0             # load          LYOTH-SP       60.00  LOAD==-0.03(0.00)
0

B2_84 "Vasco - Herdlyn 60 kV Line"
 line     33770  33772  "1 " 1     0     # line   from  HERDLYN         60.00  BRKR to (2)    B.BTHNY-      60.00
 line     33772  33773  "1 " 1     0     # line   from  B.BTHNY-        60.00   (2) to (2)    ALTA-CGE      60.00
 line     33773  33775  "1 " 1     0     # line   from  ALTA-CGE        60.00   (2) to (2)    TOSCO-PP      60.00
 line     33775  33776  "1 " 1     0     # line   from  TOSCO-PP        60.00   (2) to (2)    SOUTH BY      60.00
 line     33776  35202  "1 " 1     0     # line   from  SOUTH BY        60.00   (2) to (3)    USWP-WKR      60.00
 line     35202  35211  "1 " 1     0     # line   from  USWP-WKR        60.00   (3) to (1)    ALTAMONT      60.00
 tran     35202  35314  "1 "       0     # tran   from  USWP-WKR        60.00   (3) to (1)    WALKER+        9.11
 load     33772  "1 "    0             # load          B.BTHNY-       60.00  LOAD==1.85(0.42)
 load     33772  "E1"    0             # load          B.BTHNY-       60.00  LOAD==-0.02(0.00)
 load     33775  "1 "    0             # load          TOSCO-PP       60.00  LOAD==0.04(0.04)
 load     33775  "E1"    0             # load          TOSCO-PP       60.00  LOAD==-0.01(0.00)
 svd      35202  "v "    0             # svd           USWP-WKR       60.00
0

B2_85 "Rancho Seco - Bellota 230 kV Line No. 1"
 line     37016  30500  "1 " 1     0     # line   from  RNCHSECO       230.00  BRKR to BRKR  BELLOTA       230.00
0

B2_86 "Tesla - Tracy 230 kV Line No. 1"
 line     37585  30625  "1 " 1     0     # line   from  TRCY PMP       230.00  BRKR to BRKR  TESLA D       230.00
0

B2_87 "Tesla - Tracy 230 kV Line No. 2"
 line     37585  30625  "2 " 1     0     # line   from  TRCY PMP       230.00  BRKR to BRKR  TESLA D       230.00
0

B2_88 "Lodi Stig - Eight Mile Road 230 kV Line"
 line     38000  30622  "1 " 1     0     # line   from  LODI          230.00  BRKR to BRKR  EIGHT MI      230.00
0

B2_89 "Lodi - Industrial 60 kV Line"
 line     38060  33729  "1 " 1     0     # line   from  INDUSTRL       60.00  BRKR to BRKR  LODI AUX       60.00
0

B3_1 "Lockeford 230/60 kV Transformer No. 2"
 tran     33724  30482  "2 "       0     # tran   from  LOCKEFRD       60.00  BRKR to BRKR  LOCKFORD      230.00
0

B3_2 "Lockeford 230/60 kV Transformer No. 3"
 tran     33724  30482  "3 "       0     # tran   from  LOCKEFRD       60.00  BRKR to BRKR  LOCKFORD      230.00
0

B3_3 "Tiger Creek 230/115 kV Transformer"
 tran     30485  30486  "1 "       0     # tran   from  TIGR CRK      230.00   (3) to (3)    TIGR CKM      230.00
 line     30485  30487  "1 " 1     0     # line   from  TIGR CRK      230.00  BRKR to BRKR  ELECTRA       230.00
 line     30485  30490  "1 " 1     0     # line   from  TIGR CRK      230.00  BRKR to BRKR  VLLY SPS      230.00
 tran     30486  33584  "1 "       0     # tran   from  TIGR CKM      230.00   (3) to (2)    TIGR CRK      115.00
 tran     30486  33822  "1 "       0     # tran   from  TIGR CKM      230.00   (3) to (1)    TIGR CRK       11.00
 line     33584  39601  "1 " 1     0     # line   from  TIGR CRK      115.00  BRKR to (1)    KMPUDTAP      115.00
 load     33822  "1 "    0             # load          TIGR CRK       11.00  LOAD==0.20(0.00)
 load     33822  "E1"    0             # load          TIGR CRK       11.00  LOAD==-0.00(0.00)
 gen      33822  "1 "    0             # gen           TIGR CRK       11.00  GEN ==20.92(6.16)
 gen      33822  "2 "    0             # gen           TIGR CRK       11.00  GEN ==20.92(6.16)
0

B3_4 "Valley Springs 230/60 kV Transformer No. 1"
 tran     33610  30490  "1 "       0     # tran   from  VLLY SPS       60.00  BRKR to BRKR  VLLY SPS      230.00
0

B3_17 "Valley Springs 230/60 kV Transformer No. 2"
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 tran     33610  30490  "2 "       0     # tran   from  VLLY SPS      60.00  BRKR to BRKR  VLLY SPS      230.00
0

B3_5 "Stagg 230/60 kV Transformer No. 1"
 tran     33704  30498  "1 "       0     # tran   from  STAGG         60.00  BRKR to BRKR  STAGG-D       230.00
0

B3_6 "Stagg 230/60 kV Transformer No. 4"
 tran     33704  30499  "4 "       0     # tran   from  STAGG         60.00  BRKR to BRKR  STAGG-E       230.00
 line  30499 30489  "1 "   1  0      #Open Stagg-E-Stagg Jct2 line section
0

B3_7 "Bellota 230/115 kV Transformer No. 1"
 tran     33562  30500  "1 "       0     # tran   from  BELLOTA      115.00  BRKR to (1)   BELLOTA       230.00
0

B3_8 "Belltoa 230/115 kV Transformer No. 2"
 tran     33562  30500  "2 "       0     # tran   from  BELLOTA      115.00  BRKR to BRKR  BELLOTA       230.00
0

B3_9 "Weber 230/60 kV Transformer No. 1"
 tran     33650  30505  "1 "       0     # tran   from  WEBER 1       60.00  BRKR to BRKR  WEBER         230.00
0

B3_18 "Weber 230/60 kV Transformer No. 3"
 tran     33662  30505  "3 "       0     # tran   from  WEBER 2       60.00  BRKR to BRKR  WEBER         230.00
0

B3_11 "Tesla 230/115 kV Transformer No. 1"
 tran     33540  30625  "1 "       0     # tran   from  TESLA        115.00  BRKR to BRKR  TESLA D       230.00
0

B3_12 "Tesla 230/115 kV Transformer No. 3"
 tran     33540  30625  "3 "       0     # tran   from  TESLA        115.00  BRKR to BRKR  TESLA D       230.00
0

B3_13 "Manteca 115/60 kV Transformer No. 3"
 tran     33742  33514  "3 "       0     # tran   from  MANTECA       60.00  BRKR to BRKR  MANTECA       115.00
0

B3_14 "Kasson 115/60 kV Transformer No. 1"
 tran     33756  33528  "1 "       0     # tran   from  KASSON        60.00   (5) to BRKR  KASSON        115.00
 line     33756  33750  "1 " 1     0     # line   from  KASSON        60.00  BRKR to (1)   CALVO          60.00
 line     33756  33758  "1 " 1     0     # line   from  KASSON        60.00  BRKR to BRKR  BANTA          60.00
 line     33756  33760  "1 " 1     0     # line   from  KASSON        60.00  BRKR to (1)   BNTA JCT       60.00
 line     33756  33762  "1 " 1     0     # line   from  KASSON        60.00  BRKR to (1)   LYOTH-SP       60.00
 load     33758  "1 "    0             # load         BANTA         60.00  LOAD==5.94(0.85)
 load     33758  "E1"    0             # load         BANTA         60.00  LOAD==-0.04(0.00)
0

B3_15 "GWF Tracy 3 GSU"
 tran     33811  33551  "1 "       0     # tran   from  GWFTRCY3      13.80   (1) to BRKR  GWFTRACY      115.00
 load     33811  "ss"    0             # load         GWFTRCY3      13.80  LOAD==9.70(5.39)
 gen      33811  "1 "    0             # gen          GWFTRCY3      13.80  GEN ==154.70(15.20)
0

B3_16 "Electra GSU"
 tran     30487  33812  "1 "       0     # tran   from  ELECTRA      230.00   (3) to (1)   ELECTRA        13.80
 line     30487  30485  "1 " 1     0     # line   from  ELECTRA      230.00  BRKR to BRKR  TIGR CRK      230.00
 line     30487  30500  "1 " 1     0     # line   from  ELECTRA      230.00  BRKR to BRKR  BELLOTA       230.00
 load     33812  "1 "    0             # load         ELECTRA        13.80  LOAD==14.20(2.49)
 load     33812  "E1"    0             # load         ELECTRA        13.80  LOAD==-0.12(0.00)
 gen      33812  "1 "    0             # gen          ELECTRA        13.80  GEN ==32.70(0.44)
 gen      33812  "2 "    0             # gen          ELECTRA        13.80  GEN ==31.70(0.44)
 gen      33812  "3 "    0             # gen          ELECTRA        13.80  GEN ==33.60(0.44)
0

B1_1 "0227-WD      230.00 Unit ID FW"
 gen      30506  "FW"    0             # gen          0227-WD       230.00  GEN ==4.20(0.00)
0

B1_2 "STKTN WW      60.00 Unit ID 1"
 gen      33687  "1 "    0             # gen          STKTN WW       60.00  GEN ==1.50(0.15)
0

B1_3 "SALT SPS      11.00 Unit ID 1"
 gen      33800  "1 "    0             # gen          SALT SPS       11.00  GEN ==7.85(4.70)
0

B1_4 "SALT SPS      11.00 Unit ID 2"
```

```
 gen      33800  "2 "    0              # gen          SALT SPS      11.00  GEN ==30.12(4.70)
0

B1_5 "GWFTRCY1      13.80 Unit ID 1"
 gen      33805  "1 "    0              # gen          GWFTRCY1      13.80  GEN ==83.56(20.76)
0

B1_6 "TH.E.DV.      13.80 Unit ID 1"
 gen      33806  "1 "    0              # gen          TH.E.DV.      13.80  GEN ==18.53(6.00)
0

B1_7 "GWFTRCY2      13.80 Unit ID 1"
 gen      33807  "1 "    0              # gen          GWFTRCY2      13.80  GEN ==82.88(20.67)
0

B1_8 "SJ COGEN      13.80 Unit ID 1"
 gen      33808  "1 "    0              # gen          SJ COGEN      13.80  GEN ==48.00(6.85)
0

B1_9 "SP CMPNY      13.80 Unit ID 1"
 gen      33810  "1 "    0              # gen          SP CMPNY      13.80  GEN ==34.37(2.77)
0

B1_10 "GWFTRCY3      13.80 Unit ID 1"
 gen      33811  "1 "    0              # gen          GWFTRCY3      13.80  GEN ==154.70(15.20)
0

B1_11 "ELECTRA       13.80 Unit ID 1"
 gen      33812  "1 "    0              # gen          ELECTRA       13.80  GEN ==32.70(0.44)
0

B1_12 "ELECTRA       13.80 Unit ID 2"
 gen      33812  "2 "    0              # gen          ELECTRA       13.80  GEN ==31.70(0.44)
0

B1_13 "ELECTRA       13.80 Unit ID 3"
 gen      33812  "3 "    0              # gen          ELECTRA       13.80  GEN ==33.60(0.44)
0

B1_14 "MARIPCT1      13.80 Unit ID 1"
 gen      33813  "1 "    0              # gen          MARIPCT1      13.80  GEN ==45.95(-1.90)
0

B1_15 "CPC STCN      12.47 Unit ID 1"
 gen      33814  "1 "    0              # gen          CPC STCN      12.47  GEN ==41.60(5.07)
0

B1_16 "MARIPCT2      13.80 Unit ID 2"
 gen      33815  "2 "    0              # gen          MARIPCT2      13.80  GEN ==45.95(-1.90)
0

B1_17 "RPSP1009      13.80 Unit ID 1"
 gen      33816  "1 "    0              # gen          RPSP1009      13.80  GEN ==18.40(3.71)
0

B1_18 "MARIPCT3      13.80 Unit ID 3"
 gen      33817  "3 "    0              # gen          MARIPCT3      13.80  GEN ==45.95(-1.90)
0

B1_19 "MARIPCT4      13.80 Unit ID 4"
 gen      33819  "4 "    0              # gen          MARIPCT4      13.80  GEN ==45.95(-1.90)
0

B1_20 "WEST PNT      11.50 Unit ID 1"
 gen      33820  "1 "    0              # gen          WEST PNT      11.50  GEN ==13.60(5.48)
0

B1_21 "TIGR CRK      11.00 Unit ID 1"
 gen      33822  "1 "    0              # gen          TIGR CRK      11.00  GEN ==20.92(6.16)
0

B1_22 "TIGR CRK      11.00 Unit ID 2"
 gen      33822  "2 "    0              # gen          TIGR CRK      11.00  GEN ==20.92(6.16)
0

B1_23 "COG.CAPT       9.11 Unit ID 1"
 gen      33832  "1 "    0              # gen          COG.CAPT       9.11  GEN ==4.30(-4.40)
0

B1_24 "USWP_#4        9.11 Unit ID 3"
```

```
 gen      33836  "3 "    0              # gen          USWP_#4        9.11  GEN ==11.97(0.00)
0

B1_25 "FLOWD3-6       9.11 Unit ID 1"
 gen      33840  "1 "    0              # gen          FLOWD3-6       9.11  GEN ==5.41(0.00)
0

B1_26 "FLOWD3-6       9.11 Unit ID 2"
 gen      33840  "2 "    0              # gen          FLOWD3-6       9.11  GEN ==5.13(0.00)
0

B1_27 "PATTERSN       9.11 Unit ID 3"
 gen      33842  "3 "    0              # gen          PATTERSN       9.11  GEN ==19.34(0.00)
0

B1_28 "CAMANCHE       4.16 Unit ID 1"
 gen      33850  "1 "    0              # gen          CAMANCHE       4.16  GEN ==3.28(-2.00)
0

B1_29 "CAMANCHE       4.16 Unit ID 2"
 gen      33850  "2 "    0              # gen          CAMANCHE       4.16  GEN ==3.28(0.00)
0

B1_30 "CAMANCHE       4.16 Unit ID 3"
 gen      33850  "3 "    0              # gen          CAMANCHE       4.16  GEN ==3.28(0.00)
0

B1_31 "STANISLS      13.80 Unit ID 1"
 gen      34062  "1 "    0              # gen          STANISLS      13.80  GEN ==83.00(15.00)
0

B1_32 "LFC FIN+       9.11 Unit ID 1"
 gen      35310  "1 "    0              # gen          LFC FIN+       9.11  GEN ==3.36(0.00)
0

B1_33 "COLLRVL1      13.80 Unit ID 1"
 gen      38102  "1 "    0              # gen          COLLRVL1      13.80  GEN ==87.60(36.65)
0

B1_34 "COLLRVL2      13.80 Unit ID 1"
 gen      38104  "1 "    0              # gen          COLLRVL2      13.80  GEN ==87.60(36.65)
0

B1_35 "N.HGN DM      12.00 Unit ID 1"
 gen      38365  "1 "    0              # gen          N.HGN DM      12.00  GEN ==0.80(-0.60)
0

B1_36 "N.HGN DM      12.00 Unit ID 2"
 gen      38365  "2 "    0              # gen          N.HGN DM      12.00  GEN ==0.80(-0.33)
0

end
```

APPENDIX B – CAISO CATEGORY C CONTINGENCY LIST

```
# PG&E 2013 Assessment Series - 2015 Stockton Area 11 Category C outages (C1, C2 and C5 outages)


#C1-1 "BUS FAULT AT  30482 LOCKFORD     230.00"
#       Ring Bus
# line     30482  30330  "1 " 1      0     # line   from  LOCKFORD     230.00 to RIO OSO      230.00
# line     30482  30500  "1 " 1      0     # line   from  LOCKFORD     230.00 to BELLOTA      230.00
# tran     30482  33724  "2 "       0     # tran   from  LOCKFORD     230.00 to LOCKEFRD      60.00
# tran     30482  33724  "3 "       0     # tran   from  LOCKFORD     230.00 to LOCKEFRD      60.00
#0

#C1-2 "BUS FAULT AT  30490 VLLY SPS     230.00"
#       Ring Bus
# line     30490  30485  "1 " 1      0     # line   from  VLLY SPS     230.00 to TIGR CRK     230.00
# line     30490  30500  "1 " 1      0     # line   from  VLLY SPS     230.00 to BELLOTA      230.00
# tran     30490  33610  "1 "       0     # tran   from  VLLY SPS     230.00 to VLLY SPS      60.00
# tran     30490  33610  "2 "       0     # tran   from  VLLY SPS     230.00 to VLLY SPS      60.00
#0

#C1-3 "BUS FAULT AT  30496 STAGG-H      230.00"
#       Ring Bus
# line     30496  30495  "1 " 1      0     # line   from  STAGG-H      230.00 to STAGG        230.00
# line     30496  30497  "1 " 1      0     # line   from  STAGG-H      230.00 to STAGG-F      230.00
# tran     30496  33803  "6 "       0     # tran   from  STAGG-H      230.00 to STAGG_6       21.00
#0

#C1-4 "BUS FAULT AT  30497 STAGG-F      230.00"
#       Ring Bus
# line     30497  30496  "1 " 1      0     # line   from  STAGG-F      230.00 to STAGG-H      230.00
# line     30497  30498  "1 " 1      0     # line   from  STAGG-F      230.00 to STAGG-D      230.00
# tran     30497  33801  "5 "       0     # tran   from  STAGG-F      230.00 to STAGG_5       21.00
#0

#C1-5 "BUS FAULT AT  30498 STAGG-D      230.00"
#       Ring Bus
# line     30498  30497  "1 " 1      0     # line   from  STAGG-D      230.00 to STAGG-F      230.00
# line     30498  30499  "1 " 1      0     # line   from  STAGG-D      230.00 to STAGG-E      230.00
# tran     30498  33704  "1 "       0     # tran   from  STAGG-D      230.00 to STAGG         60.00
#0

#C1-6 "BUS FAULT AT  30499 STAGG-E      230.00"
#       Ring Bus
# line     30499  30498  "1 " 1      0     # line   from  STAGG-E      230.00 to STAGG-D      230.00
# line     30499  30489  "1 " 1      0     # line   from  STAGG-E      230.00 to STAGG-J2     230.00
# tran     30499  33704  "4 "       0     # tran   from  STAGG-E      230.00 to STAGG         60.00
#0

C1_1 "BUS FAULT AT  30500 BELLOTA      230.00 Bus 1"
 line     30500  30348  "1 " 1      0     # line   from  BELLOTA      230.00 to BRIGHTON     230.00
 line     30500  30487  "1 " 1      0     # line   from  BELLOTA      230.00 to ELECTRA      230.00
 line     30500  30503  "2 " 1      0     # line   from  BELLOTA      230.00 to COLLERVL     230.00
 line     30500  30505  "1 " 1      0     # line   from  BELLOTA      230.00 to WEBER        230.00
 line     30500  38206  "1 " 1      0     # line   from  BELLOTA      230.00 to COTTLE       230.00
 line     30500  37016  "1 " 1      0     # line   from  BELLOTA      230.00 to RNCHSECO     230.00
 tran     30500  33809  "1 "       0     # tran   from  BELLOTA      230.00 to BLLTA 1M      13.20
0

C1_2 "BUS FAULT AT  30500 BELLOTA      230.00 Bus 2"
 line     30500  30482  "1 " 1      0     # line   from  BELLOTA      230.00 to LOCKFORD     230.00
 line     30500  30490  "1 " 1      0     # line   from  BELLOTA      230.00 to VLLY SPS     230.00
 line     30500  30503  "1 " 1      0     # line   from  BELLOTA      230.00 to COLLERVL     230.00
 line     30500  30624  "1 " 1      0     # line   from  BELLOTA      230.00 to TESLA E      230.00
 line     30500  30510  "2 " 1      0     # line   from  BELLOTA      230.00 to CAMANCH      230.00
 tran     30500  33562  "2 "       0     # tran   from  BELLOTA      230.00 to BELLOTA      115.00
0

C1_3 "BUS FAULT AT  30503 COLLERVL     230.00"
 line     30503  30500  "1 " 1      0     # line   from  COLLERVL     230.00 to BELLOTA      230.00
 line     30503  30500  "2 " 1      0     # line   from  COLLERVL     230.00 to BELLOTA      230.00
 tran     30503  38102  "1 "       0     # tran   from  COLLERVL     230.00 to COLLRVL1      13.80
 tran     30503  38104  "1 "       0     # tran   from  COLLERVL     230.00 to COLLRVL2      13.80
0

C1_4 "BUS FAULT AT  30505 WEBER        230.00"
 line     30505  30500  "1 " 1      0     # line   from  WEBER        230.00 to BELLOTA      230.00
 line     30505  30624  "1 " 1      0     # line   from  WEBER        230.00 to TESLA E      230.00
 line     30505  30506  "1 " 1      0     # line   from  WEBER        230.00 to 0227-WD      230.00
 tran     30505  33650  "1 "       0     # tran   from  WEBER        230.00 to WEBER 1       60.00
 tran     30505  33662  "3 "       0     # tran   from  WEBER        230.00 to WEBER 2       60.00
```

```
 load     30505  "5 "    0              # load         WEBER        230.00  LOAD==22.58(3.22)
 load     30505  "6 "    0              # load         WEBER        230.00  LOAD==13.73(1.95)
 load     30505  "E5"    0              # load         WEBER        230.00  LOAD==-0.24(0.00)
0

C1_5 "BUS FAULT AT  30569 KELSO        230.00"
 line     30569  30565  "1 " 1     0     # line   from  KELSO        230.00 to BRENTWOD     230.00
 line     30569  30568  "1 " 1     0     # line   from  KELSO        230.00 to MARIPOSA     230.00
 line     30569  30570  "1 " 1     0     # line   from  KELSO        230.00 to USWP-RLF     230.00
 load     30569  "1 "    0              # load         KELSO        230.00  LOAD==7.39(4.58)
 load     30569  "E1"    0              # load         KELSO        230.00  LOAD==-0.06(0.00)
0

#C1-10 "BUS FAULT AT  30622 EIGHT MI     230.00"
#       Ring Bus
# line     30622  30337  "1 " 1     0     # line   from  EIGHT MI     230.00 to GOLDHILL     230.00
# line     30622  30495  "1 " 1     0     # line   from  EIGHT MI     230.00 to STAGG        230.00
# line     30622  30624  "1 " 1     0     # line   from  EIGHT MI     230.00 to TESLA E      230.00
# line     30622  38000  "1 " 1     0     # line   from  EIGHT MI     230.00 to LODI         230.00
# load     30622  "2 "    0              # load         EIGHT MI     230.00  LOAD==22.61(3.22)
# load     30622  "3 "    0              # load         EIGHT MI     230.00  LOAD==27.65(3.94)
# load     30622  "E2"    0              # load         EIGHT MI     230.00  LOAD==-0.00(0.00)
# load     30622  "E3"    0              # load         EIGHT MI     230.00  LOAD==-0.00(0.00)
#0

C1_6 "BUS FAULT AT  30624 TESLA E      230.00 Bus 1"
 line     30624  30505  "1 " 1     0     # line   from  TESLA E      230.00 to WEBER        230.00
 line     30624  30622  "1 " 1     0     # line   from  TESLA E      230.00 to EIGHT MI     230.00
 line     30624  30630  "1 " 1     0     # line   from  TESLA E      230.00 to NEWARK D     230.00
0

C1_7 "BUS FAULT AT  30624 TESLA E      230.00 Bus 2"
 line     30624  30489  "1 " 1     0     # line   from  TESLA E      230.00 to STAGG-J2     230.00
 line     30624  30500  "1 " 1     0     # line   from  TESLA E      230.00 to BELLOTA      230.00
 line     30624  30670  "1 " 1     0     # line   from  TESLA E      230.00 to WESTLEY      230.00
 line     30624  30703  "1 " 1     0     # line   from  TESLA E      230.00 to RAVENSWD     230.00
0

C1_8 "BUS FAULT AT  30625 TESLA D      230.00 Bus 1"
 line     30625  30570  "1 " 1     0     # line   from  TESLA D      230.00 to USWP-RLF     230.00
 line     30625  37585  "1 " 1     0     # line   from  TESLA D      230.00 to TRCY PMP     230.00
 tran     30625  33540  "1 "       0     # tran   from  TESLA D      230.00 to TESLA        115.00
0

C1_9 "BUS FAULT AT  30625 TESLA D      230.00 Bus 2"
 line     30625  30580  "1 " 1     0     # line   from  TESLA D      230.00 to ALTM MDW     230.00
 line     30625  37585  "2 " 1     0     # line   from  TESLA D      230.00 to TRCY PMP     230.00
 tran     30625  33540  "3 "       0     # tran   from  TESLA D      230.00 to TESLA        115.00
 svd      30625  "v "    0              # svd          TESLA D      230.00
0

C1_10 "BUS FAULT AT  30640 TESLA C      230.00"
 line     30640  30595  "1 " 1     0     # line   from  TESLA C      230.00 to FLOWIND2     230.00
 line     30640  30600  "2 " 1     0     # line   from  TESLA C      230.00 to TRES VAQ     230.00
 line     30640  30625  "1 " 1     0     # line   from  TESLA C      230.00 to TESLA D      230.00
 line     30640  30655  "2 " 1     0     # line   from  TESLA C      230.00 to ADCC         230.00
 tran     30640  30040  "6 "       0     # tran   from  TESLA C      230.00 to TESLA        500.00
0

C1_11 "BUS FAULT AT  33506 STANISLS     115.00"
 line     33506  33501  "1 " 1     0     # line   from  STANISLS     115.00 to FRGTNTP1     115.00
 line     33506  33504  "1 " 1     0     # line   from  STANISLS     115.00 to CATARACT     115.00
 line     33506  33948  "1 " 1     0     # line   from  STANISLS     115.00 to RVRBK J2     115.00
 tran     33506  34062  "1 "       0     # tran   from  STANISLS     115.00 to STANISLS      13.80
 load     33506  "2 "    0              # load         STANISLS     115.00  LOAD==9.68(1.38)
 load     33506  "E2"    0              # load         STANISLS     115.00  LOAD==-0.04(0.00)
0

#C1-16 "BUS FAULT AT  33514 MANTECA      115.00"
#       Ring Bus
# line     33514  33509  "1 " 1     0     # line   from  MANTECA      115.00 to AVENATP1     115.00
# line     33514  33511  "1 " 1     0     # line   from  MANTECA      115.00 to AVENATP2     115.00
# line     33514  33526  "1 " 1     0     # line   from  MANTECA      115.00 to KSSN-JC1     115.00
# line     33514  33970  "1 " 1     0     # line   from  MANTECA      115.00 to INGRM C.     115.00
# line     33514  33516  "1 " 1     0     # line   from  MANTECA      115.00 to RPN JNCN     115.00
# line     33514  33518  "1 " 1     0     # line   from  MANTECA      115.00 to VIERRA       115.00
# tran     33514  33742  "3 "       0     # tran   from  MANTECA      115.00 to MANTECA       60.00
# load     33514  "5 "    0              # load         MANTECA      115.00  LOAD==21.19(3.02)
# load     33514  "6 "    0              # load         MANTECA      115.00  LOAD==22.63(3.22)
# load     33514  "7 "    0              # load         MANTECA      115.00  LOAD==21.98(3.14)
```

```
# load     33514  "8 "    0              # load         MANTECA      115.00  LOAD==26.06(3.71)
# load     33514  "E5"    0              # load         MANTECA      115.00  LOAD==-0.11(0.00)
# load     33514  "E6"    0              # load         MANTECA      115.00  LOAD==-0.12(0.00)
# load     33514  "E7"    0              # load         MANTECA      115.00  LOAD==-0.13(0.00)
# load     33514  "E8"    0              # load         MANTECA      115.00  LOAD==-0.12(0.00)
#0

C1_12 "BUS FAULT AT  33518 VIERRA       115.00"
 line     33518  33514  "1 " 1     0     # line   from  VIERRA       115.00 to MANTECA      115.00
 line     33518  33522  "1 " 1     0     # line   from  VIERRA       115.00 to CROSRDJT     115.00
 load     33518  "1 "    0              # load         VIERRA       115.00  LOAD==30.03(4.28)
 load     33518  "2 "    0              # load         VIERRA       115.00  LOAD==21.59(3.08)
 load     33518  "E1"    0              # load         VIERRA       115.00  LOAD==-0.19(0.00)
 load     33518  "E2"    0              # load         VIERRA       115.00  LOAD==-0.07(0.00)
0

C1_38 "BUS FAULT AT  33520 RIPON        115.00"
 line     33520  33516  "1 " 1     0     # line   from  RIPON        115.00 to RPN JNCN     115.00
 line     33520  33517  "1 " 1     0     # line   from  RIPON        115.00 to RPNJN2       115.00
 load     33520  "2 "    0              # load         RIPON        115.00  LOAD==23.75(3.38)
 load     33520  "E2"    0              # load         RIPON        115.00  LOAD==-0.12(0.00)
0

C1_13 "BUS FAULT AT  33528 KASSON       115.00"
 line     33528  33526  "1 " 1     0     # line   from  KASSON       115.00 to KSSN-JC1     115.00
 line     33528  33530  "1 " 1     0     # line   from  KASSON       115.00 to KSSN-JC2     115.00
 line     33528  33531  "1 " 1     0     # line   from  KASSON       115.00 to OWENSTP1     115.00
 tran     33528  33756  "1 "       0     # tran   from  KASSON       115.00 to KASSON        60.00
0

#C1-18 "BUS FAULT AT  33529 LAMMERS      115.00"
# Ring Bus
# line     33529  33531  "1 " 1     0     # line   from  LAMMERS      115.00 to OWENSTP1     115.00
# line     33529  33549  "1 " 1     0     # line   from  LAMMERS      115.00 to SCHULTE      115.00
# load     33529  "1 "    0              # load         LAMMERS      115.00  LOAD==26.42(3.76)
# load     33529  "2 "    0              # load         LAMMERS      115.00  LOAD==29.76(4.24)
# load     33529  "E1"    0              # load         LAMMERS      115.00  LOAD==-0.00(0.00)
# load     33529  "E2"    0              # load         LAMMERS      115.00  LOAD==-0.00(0.00)
#0

C1_14 "BUS FAULT AT  33540 TESLA        115.00 Bus 1"
 line     33540  33543  "1 " 1     0     # line   from  TESLA        115.00 to AEC_TP2      115.00
 line     33540  33576  "1 " 1     0     # line   from  TESLA        115.00 to USWP-PAT     115.00
 line     33540  33961  "1 " 1     0     # line   from  TESLA        115.00 to TCHRT_T1     115.00
 tran     33540  30625  "1 "       0     # tran   from  TESLA        115.00 to TESLA_D      230.00
0

C1_15 "BUS FAULT AT  33540 TESLA        115.00 Bus 2"
 line     33540  33541  "1 " 1     0     # line   from  TESLA        115.00 to AEC_TP1      115.00
 line     33540  33544  "1 " 1     0     # line   from  TESLA        115.00 to ELLS GTY     115.00
 line     33540  33568  "1 " 1     0     # line   from  TESLA        115.00 to TH.E.DV.     115.00
 line     33540  33574  "1 " 1     0     # line   from  TESLA        115.00 to LLNL TAP     115.00
 line     33540  33959  "1 " 1     0     # line   from  TESLA        115.00 to TCHRT_T2     115.00
 tran     33540  30625  "3 "       0     # tran   from  TESLA        115.00 to TESLA_D      230.00
0

C1_16 "BUS FAULT AT  33548 TRACY        115.00"
 line     33548  33542  "1 " 1     0     # line   from  TRACY        115.00 to LEPRINO      115.00
 line     33548  33550  "1 " 1     0     # line   from  TRACY        115.00 to HJ HEINZ     115.00
 load     33548  "1 "    0              # load         TRACY        115.00  LOAD==24.32(3.47)
 load     33548  "2 "    0              # load         TRACY        115.00  LOAD==23.92(3.41)
 load     33548  "3 "    0              # load         TRACY        115.00  LOAD==27.47(3.92)
 load     33548  "4 "    0              # load         TRACY        115.00  LOAD==0.65(0.09)
 load     33548  "E1"    0              # load         TRACY        115.00  LOAD==-0.12(0.00)
 load     33548  "E2"    0              # load         TRACY        115.00  LOAD==-0.16(0.00)
 load     33548  "E3"    0              # load         TRACY        115.00  LOAD==-0.13(0.00)
 load     33548  "E4"    0              # load         TRACY        115.00  LOAD==-0.04(0.00)
0

#C1-23 "BUS FAULT AT  33549 SCHULTE      115.00"
#       Ring Bus
# line     33549  33535  "2 " 1     0     # line   from  SCHULTE      115.00 to SFWY_TP2     115.00
# line     33549  33537  "1 " 1     0     # line   from  SCHULTE      115.00 to SFWY_TP1     115.00
# line     33549  33529  "1 " 1     0     # line   from  SCHULTE      115.00 to LAMMERS      115.00
# line     33549  33533  "2 " 1     0     # line   from  SCHULTE      115.00 to OWENSTP2     115.00
# line     33549  33551  "1 " 1     0     # line   from  SCHULTE      115.00 to GWFTRACY     115.00
#0

C1_17 "BUS FAULT AT  33551 GWFTRACY     115.00"
 line     33551  33549  "1 " 1     0     # line   from  GWFTRACY     115.00 to SCHULTE      115.00
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```
 tran     33551  33805  "1 "        0     # tran   from  GWFTRACY     115.00 to GWFTRCY1      13.80
 tran     33551  33807  "1 "        0     # tran   from  GWFTRACY     115.00 to GWFTRCY2      13.80
 tran     33551  33811  "1 "        0     # tran   from  GWFTRACY     115.00 to GWFTRCY3      13.80
0

C1_18 "BUS FAULT AT  33562 BELLOTA      115.00 Bus 1"
 line     33562  33560  "1 " 1      0     # line   from  BELLOTA      115.00 to LCKFRDJA     115.00
 line     33562  33561  "1 " 1      0     # line   from  BELLOTA      115.00 to BLLTAJCT     115.00
 line     33562  33946  "1 " 1      0     # line   from  BELLOTA      115.00 to RVRBK J1     115.00
 tran     33562  33809  "1 "        0     # tran   from  BELLOTA      115.00 to BLLTA 1M      13.20
0

C1_19 "BUS FAULT AT  33562 BELLOTA      115.00 Bus 2"
 line     33562  33558  "1 " 1      0     # line   from  BELLOTA      115.00 to LCKFRDJB     115.00
 line     33562  33950  "1 " 1      0     # line   from  BELLOTA      115.00 to RVRBK TP     115.00
 tran     33562  30500  "2 "        0     # tran   from  BELLOTA      115.00 to BELLOTA      230.00
0

C1_20 "BUS FAULT AT  33564 LOCKFORD     115.00"
 line     33564  33558  "1 " 1      0     # line   from  LOCKFORD     115.00 to LCKFRDJB     115.00
 line     33564  33560  "1 " 1      0     # line   from  LOCKFORD     115.00 to LCKFRDJA     115.00
 line     33564  33561  "1 " 1      0     # line   from  LOCKFORD     115.00 to BLLTAJCT     115.00
 tran     33564  33725  "1 "        0     # tran   from  LOCKFORD     115.00 to LOCKFRD1      60.00
 load     33564  "4 "     0             # load         LOCKFORD     115.00  LOAD==19.44(2.77)
 load     33564  "E4"     0             # load         LOCKFORD     115.00  LOAD==-0.10(0.00)
0

C1_21 "BUS FAULT AT  33566 CAMANCHE     115.00"
 line     33566  33565  "1 " 1      0     # line   from  CAMANCHE     115.00 to CMNCHETP     115.00
 tran     33566  33850  "1 "        0     # tran   from  CAMANCHE     115.00 to CAMANCHE       4.16
0

C1_22 "BUS FAULT AT  33610 VLLY SPS      60.00"
 line     33610  33607  "1 " 1      0     # line   from  VLLY SPS      60.00 to ELECTRAJ      60.00
 line     33610  33612  "1 " 1      0     # line   from  VLLY SPS      60.00 to N BRANCH      60.00
 line     33610  33619  "1 " 1      0     # line   from  VLLY SPS      60.00 to AMFOR_SW      60.00
 line     33610  33629  "2 " 1      0     # line   from  VLLY SPS      60.00 to PRDEJCT       60.00
 line     33610  33630  "1 " 1      0     # line   from  VLLY SPS      60.00 to PARDEE A      60.00
 line     33610  33634  "1 " 1      0     # line   from  VLLY SPS      60.00 to PRDESWS       60.00
 line     33610  33636  "1 " 1      0     # line   from  VLLY SPS      60.00 to N.HGN JT      60.00
 tran     33610  30490  "1 "        0     # tran   from  VLLY SPS      60.00 to VLLY SPS     230.00
 tran     33610  30490  "2 "        0     # tran   from  VLLY SPS      60.00 to VLLY SPS     230.00
0

C1_23 "BUS FAULT AT  33614 CAL CMNT      60.00"
 line     33614  33612  "1 " 1      0     # line   from  CAL CMNT      60.00 to N BRANCH      60.00
 load     33614  "1 "     0             # load         CAL CMNT      60.00  LOAD==9.99(1.42)
 load     33614  "E1"     0             # load         CAL CMNT      60.00  LOAD==-0.05(0.00)
0

C1_24 "BUS FAULT AT  33616 MARTELL       60.00"
 line     33616  33617  "1 " 1      0     # line   from  MARTELL       60.00 to MARTELTP      60.00
 line     33616  33619  "1 " 1      0     # line   from  MARTELL       60.00 to AMFOR_SW      60.00
 load     33616  "1 "     0             # load         MARTELL       60.00  LOAD==16.28(2.32)
 load     33616  "E1"     0             # load         MARTELL       60.00  LOAD==-0.08(0.00)
0

C1_25 "BUS FAULT AT  33650 WEBER 1       60.00"
 line     33650  33646  "1 " 1      0     # line   from  WEBER 1       60.00 to MORMON        60.00
 line     33650  33647  "1 " 1      0     # line   from  WEBER 1       60.00 to WEBER016      60.00
 line     33650  33662  "1 " 1      0     # line   from  WEBER 1       60.00 to WEBER 2       60.00
 line     33650  33672  "1 " 1      0     # line   from  WEBER 1       60.00 to CHRTRWYS      60.00
 line     33650  33698  "1 " 1      0     # line   from  WEBER 1       60.00 to FRNCH CP      60.00
 tran     33650  30505  "1 "        0     # tran   from  WEBER 1       60.00 to WEBER        230.00
 load     33650  "3 "     0             # load         WEBER 1       60.00  LOAD==17.36(2.47)
 load     33650  "4 "     0             # load         WEBER 1       60.00  LOAD==17.59(2.51)
 load     33650  "E3"     0             # load         WEBER 1       60.00  LOAD==-0.10(0.00)
 load     33650  "E4"     0             # load         WEBER 1       60.00  LOAD==-0.10(0.00)
#0
#C1-32 "BUS FAULT AT  33662 WEBER 2       60.00"
 line     33662  33650  "1 " 1      0     # line   from  WEBER 2       60.00 to WEBER 1       60.00
 line     33662  33654  "1 " 1      0     # line   from  WEBER 2       60.00 to SNTA FEA      60.00
 line     33662  33658  "1 " 1      0     # line   from  WEBER 2       60.00 to SNTA FEB      60.00
 line     33662  33674  "1 " 1      0     # line   from  WEBER 2       60.00 to HAZLTN J      60.00
 tran     33662  30505  "3 "        0     # tran   from  WEBER 2       60.00 to WEBER        230.00
0

C1_26 "BUS FAULT AT  33670 STCKTN A      60.00"
 line     33670  33602  "1 " 1      0     # line   from  STCKTN A      60.00 to NEWARKS       60.00
 line     33670  33654  "1 " 1      0     # line   from  STCKTN A      60.00 to SNTA FEA      60.00
```

```
 line     33670  33658  "1 " 1     0     # line   from  STCKTN A      60.00 to SNTA FEB      60.00
 line     33670  33674  "1 " 1     0     # line   from  STCKTN A      60.00 to HAZLTN J      60.00
 load     33670  "1 "    0             # load         STCKTN A      60.00  LOAD==1.20(0.17)
 load     33670  "2 "    0             # load         STCKTN A      60.00  LOAD==1.20(0.17)
 load     33670  "E1"    0             # load         STCKTN A      60.00  LOAD==-0.01(0.00)
 load     33670  "E2"    0             # load         STCKTN A      60.00  LOAD==-0.01(0.00)
0

C1_27 "BUS FAULT AT  33704 STAGG         60.00 Section D"
 line     33704  33693  "1 " 1     0     # line   from  STAGG        60.00 to STAGG JT      60.00
 line     33704  33714  "1 " 1     0     # line   from  STAGG        60.00 to HAMMER        60.00
 tran     33704  30498  "1 "       0     # tran   from  STAGG        60.00 to STAGG-D      230.00
 load     33704  "2 "    0             # load         STAGG        60.00  LOAD==14.56(2.07)
 load     33704  "3 "    0             # load         STAGG        60.00  LOAD==15.61(2.23)
 load     33704  "E2"    0             # load         STAGG        60.00  LOAD==-0.04(0.00)
 load     33704  "E3"    0             # load         STAGG        60.00  LOAD==-0.04(0.00)
0

C1_28 "BUS FAULT AT  33704 STAGG         60.00 Section E"
 line     33704  33706  "1 " 1     0     # line   from  STAGG        60.00 to CNTRY CB      60.00
 line     33704  33706  "2 " 1     0     # line   from  STAGG        60.00 to CNTRY CB      60.00
 tran     33704  30499  "4 "       0     # tran   from  STAGG        60.00 to STAGG-E      230.00
0

C1_29 "BUS FAULT AT  33706 CNTRY CB      60.00"
 line     33706  33704  "1 " 1     0     # line   from  CNTRY CB     60.00 to STAGG         60.00
 line     33706  33704  "2 " 1     0     # line   from  CNTRY CB     60.00 to STAGG         60.00
 line     33706  33708  "1 " 1     0     # line   from  CNTRY CB     60.00 to UOP           60.00
 load     33706  "1 "    0             # load         CNTRY CB     60.00  LOAD==2.60(0.37)
 load     33706  "2 "    0             # load         CNTRY CB     60.00  LOAD==6.74(0.96)
 load     33706  "3 "    0             # load         CNTRY CB     60.00  LOAD==7.60(1.08)
 load     33706  "4 "    0             # load         CNTRY CB     60.00  LOAD==9.14(1.30)
 load     33706  "E1"    0             # load         CNTRY CB     60.00  LOAD==-0.02(0.00)
 load     33706  "E2"    0             # load         CNTRY CB     60.00  LOAD==-0.04(0.00)
 load     33706  "E3"    0             # load         CNTRY CB     60.00  LOAD==-0.06(0.00)
 load     33706  "E4"    0             # load         CNTRY CB     60.00  LOAD==-0.06(0.00)
0

C1_30 "BUS FAULT AT  33714 HAMMER        60.00"
 line     33714  33704  "1 " 1     0     # line   from  HAMMER       60.00 to STAGG         60.00
 line     33714  33716  "1 " 1     0     # line   from  HAMMER       60.00 to HMMR JCT      60.00
 load     33714  "1 "    0             # load         HAMMER       60.00  LOAD==18.85(2.69)
 load     33714  "2 "    0             # load         HAMMER       60.00  LOAD==14.24(2.03)
 load     33714  "3 "    0             # load         HAMMER       60.00  LOAD==9.86(1.40)
 load     33714  "E1"    0             # load         HAMMER       60.00  LOAD==-0.10(0.00)
 load     33714  "E2"    0             # load         HAMMER       60.00  LOAD==-0.07(0.00)
 load     33714  "E3"    0             # load         HAMMER       60.00  LOAD==-0.08(0.00)
0

C1_31 "BUS FAULT AT  33724 LOCKEFRD      60.00"
 line     33724  33630  "1 " 1     0     # line   from  LOCKEFRD     60.00 to PARDEE A      60.00
 line     33724  33725  "1 " 1     0     # line   from  LOCKEFRD     60.00 to LOCKFRD1      60.00
 line     33724  33726  "1 " 1     0     # line   from  LOCKEFRD     60.00 to VICTOR        60.00
 line     33724  33736  "1 " 1     0     # line   from  LOCKEFRD     60.00 to LODI JCT      60.00
 line     33724  33739  "1 " 1     0     # line   from  LOCKEFRD     60.00 to HNYLNJCT      60.00
 line     33724  38060  "1 " 1     0     # line   from  LOCKEFRD     60.00 to INDUSTRL      60.00
 tran     33724  30482  "2 "       0     # tran   from  LOCKEFRD     60.00 to LOCKFORD     230.00
 tran     33724  30482  "3 "       0     # tran   from  LOCKEFRD     60.00 to LOCKFORD     230.00
0

C1_32 "BUS FAULT AT  33728 LODI          60.00"
 line     33728  33729  "1 " 1     0     # line   from  LODI         60.00 to LODI AUX      60.00
 line     33728  33734  "1 " 1     0     # line   from  LODI         60.00 to CLNY JCT      60.00
 line     33728  33737  "1 " 1     0     # line   from  LODI         60.00 to WINERY J      60.00
 load     33728  "2 "    0             # load         LODI         60.00  LOAD==15.78(2.25)
 load     33728  "E2"    0             # load         LODI         60.00  LOAD==-0.09(0.00)
0

C1_33 "BUS FAULT AT  33729 LODI AUX      60.00"
 line     33729  33728  "1 " 1     0     # line   from  LODI AUX     60.00 to LODI          60.00
 line     33729  33736  "1 " 1     0     # line   from  LODI AUX     60.00 to LODI JCT      60.00
 line     33729  38060  "1 " 1     0     # line   from  LODI AUX     60.00 to INDUSTRL      60.00
0

C1_34 "BUS FAULT AT  33740 MSHR 60V      60.00"
 line     33740  33717  "1 " 1     0     # line   from  MSHR 60V     60.00 to MORADAJT      60.00
 line     33740  33738  "1 " 1     0     # line   from  MSHR 60V     60.00 to WATRLJCT      60.00
 load     33740  "1 "    0             # load         MSHR 60V     60.00  LOAD==16.98(2.42)
 load     33740  "2 "    0             # load         MSHR 60V     60.00  LOAD==11.29(1.61)
 load     33740  "3 "    0             # load         MSHR 60V     60.00  LOAD==23.70(3.37)
```

```
 load     33740  "E1"    0              # load         MSHR 60V      60.00  LOAD==-0.11(0.00)
 load     33740  "E2"    0              # load         MSHR 60V      60.00  LOAD==-0.14(0.00)
0

C1_35 "BUS FAULT AT  33742 MANTECA       60.00"
 line     33742  33703  "1 " 1     0     # line   from  MANTECA      60.00 to LOUISJCT      60.00
 line     33742  33752  "1 " 1     0     # line   from  MANTECA      60.00 to LTHRP JT      60.00
 line     33742  33743  "1 " 1     0     # line   from  MANTECA      60.00 to LEE_JCT       60.00
 tran     33742  33514  "3 "       0     # tran   from  MANTECA      60.00 to MANTECA      115.00
0

C1_36 "BUS FAULT AT  33746 LOUISE        60.00"
 line     33746  33703  "1 " 1     0     # line   from  LOUISE       60.00 to LOUISJCT      60.00
 line     33746  33748  "1 " 1     0     # line   from  LOUISE       60.00 to MSSDLESW      60.00
 load     33746  "1 "    0              # load         LOUISE       60.00  LOAD==1.43(1.15)
 load     33746  "E1"    0              # load         LOUISE       60.00  LOAD==-0.02(0.00)
0

C1_37 "BUS FAULT AT  33758 BANTA         60.00"
 line     33758  33756  "1 " 1     0     # line   from  BANTA        60.00 to KASSON        60.00
 load     33758  "1 "    0              # load         BANTA        60.00  LOAD==5.94(0.85)
 load     33758  "E1"    0              # load         BANTA        60.00  LOAD==-0.04(0.00)
0


# Program: pge-sstools-contingency-make-v2c.p   Tue Jun 12 14:10:15 2013
# Input Case: "C:\Data\Projects\Assessment\2013Assessment\Contingency_List\Cases\a12_sum2013_pge_cvly.sav"
# Input File: "C:\Data\Projects\Assessment\2013Assessment\Breaker_List\2013-master-list.in"
# area_numbers  "11"
# zone_numbers  "0"
# voltage_range  "1 230"
# bus_fault_opt  "yes"
# Output File (this output): "C:\Data\Projects\Assessment\2013Assessment\Contingency_List\a11_C1_2013.otg"
# Batch file: "C:\Data\Projects\Assessment\2013Assessment\Contingency_List\batch.txt"

 #PG&E 2013 TRANSMISSION EXPANSION PLAN ASSESSMENT
 #FINAL 2015 CENTRAL VALLEY SUMPK CASE
 #2013 Load Forecast Used (3/23/12)
C2-1 "BELLOTA 230 kV Bus 1 and Bus 2 - CB 200 Failure"
 line     30500  30348  "1 " 1     0     # line   from  BELLOTA      230.00 to BRIGHTON     230.00
 line     30500  30487  "1 " 1     0     # line   from  BELLOTA      230.00 to ELECTRA      230.00
 line     30500  30503  "2 " 1     0     # line   from  BELLOTA      230.00 to COLLERVL     230.00
 line     30500  30505  "1 " 1     0     # line   from  BELLOTA      230.00 to WEBER        230.00
 line     30500  38206  "1 " 1     0     # line   from  BELLOTA      230.00 to COTTLE       230.00
 line     30500  37016  "1 " 1     0     # line   from  BELLOTA      230.00 to RNCHSECO     230.00
 tran     30500  33809  "1 "       0     # tran   from  BELLOTA      230.00 to BLLTA 1M      13.20
#
 line     30500  30482  "1 " 1     0     # line   from  BELLOTA      230.00 to LOCKFORD     230.00
 line     30500  30490  "1 " 1     0     # line   from  BELLOTA      230.00 to VLLY SPS     230.00
 line     30500  30503  "1 " 1     0     # line   from  BELLOTA      230.00 to COLLERVL     230.00
 line     30500  30624  "1 " 1     0     # line   from  BELLOTA      230.00 to TESLA E      230.00
 line     30500  30510  "2 " 1     0     # line   from  BELLOTA      230.00 to CAMANCH      230.00
 tran     30500  33562  "2 "       0     # tran   from  BELLOTA      230.00 to BELLOTA      115.00
0

C2-2 "TESLA E 230 kV Bus 1 and Bus 2 - CB 202 Failure"
 line     30624  30505  "1 " 1     0     # line   from  TESLA E      230.00 to WEBER        230.00
 line     30624  30622  "1 " 1     0     # line   from  TESLA E      230.00 to EIGHT MI     230.00
 line     30624  30630  "1 " 1     0     # line   from  TESLA E      230.00 to NEWARK D     230.00
#
 line     30624  30489  "1 " 1     0     # line   from  TESLA E      230.00 to STAGG-J2     230.00
 line     30624  30500  "1 " 1     0     # line   from  TESLA E      230.00 to BELLOTA      230.00
 line     30624  30670  "1 " 1     0     # line   from  TESLA E      230.00 to WESTLEY      230.00
 line     30624  30703  "1 " 1     0     # line   from  TESLA E      230.00 to RAVENSWD     230.00
0

C2-3 "TESLA E 230 kV Bus 1 and TESLA D 230 kV Bus 1 - CB 812 Failure"
 line     30624  30505  "1 " 1     0     # line   from  TESLA E      230.00 to WEBER        230.00
 line     30624  30622  "1 " 1     0     # line   from  TESLA E      230.00 to EIGHT MI     230.00
 line     30624  30630  "1 " 1     0     # line   from  TESLA E      230.00 to NEWARK D     230.00
#
 line     30625  30570  "1 " 1     0     # line   from  TESLA D      230.00 to USWP-RLF     230.00
 line     30625  37585  "1 " 1     0     # line   from  TESLA D      230.00 to TRCY PMP     230.00
 tran     30625  33540  "1 "       0     # tran   from  TESLA D      230.00 to TESLA        115.00
0

C2-4 "TESLA E 230 kV Bus 2 and TESLA D 230 kV Bus 2 - CB 822 Failure"
 line     30624  30489  "1 " 1     0     # line   from  TESLA E      230.00 to STAGG-J2     230.00
 line     30624  30500  "1 " 1     0     # line   from  TESLA E      230.00 to BELLOTA      230.00
 line     30624  30670  "1 " 1     0     # line   from  TESLA E      230.00 to WESTLEY      230.00
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```
 line      30624  30703  "1 " 1     0     # line   from  TESLA E      230.00 to RAVENSWD     230.00
#
 line      30625  30580  "1 " 1     0     # line   from  TESLA D      230.00 to ALTM MDW     230.00
 line      30625  37585  "2 " 1     0     # line   from  TESLA D      230.00 to TRCY PMP     230.00
 tran      30625  33540  "3 "       0     # tran   from  TESLA D      230.00 to TESLA        115.00
 svd       30625  "v "    0             # svd          TESLA D      230.00
0

C2-5 "TESLA D 230 kV Bus 1 and Bus 2 - No Bus 1 Bus 2 separating CB so not Real"
 line      30625  30570  "1 " 1     0     # line   from  TESLA D      230.00 to USWP-RLF     230.00
 line      30625  37585  "1 " 1     0     # line   from  TESLA D      230.00 to TRCY PMP     230.00
 tran      30625  33540  "1 "       0     # tran   from  TESLA D      230.00 to TESLA        115.00
#
 line      30625  30580  "1 " 1     0     # line   from  TESLA D      230.00 to ALTM MDW     230.00
 line      30625  37585  "2 " 1     0     # line   from  TESLA D      230.00 to TRCY PMP     230.00
 tran      30625  33540  "3 "       0     # tran   from  TESLA D      230.00 to TESLA        115.00
 svd       30625  "v "    0             # svd          TESLA D      230.00
0

C2-6 "TESLA 115 kV Bus 1 and Bus 2 - CB 102 Failure"
 line      33540  33543  "1 " 1     0     # line   from  TESLA        115.00 to AEC_TP2      115.00
 line      33540  33576  "1 " 1     0     # line   from  TESLA        115.00 to USWP-PAT     115.00
 line      33540  33961  "1 " 1     0     # line   from  TESLA        115.00 to TCHRT_T1     115.00
 tran      33540  30625  "1 "       0     # tran   from  TESLA        115.00 to TESLA_D      230.00
#
 line      33540  33541  "1 " 1     0     # line   from  TESLA        115.00 to AEC_TP1      115.00
 line      33540  33544  "1 " 1     0     # line   from  TESLA        115.00 to ELLS GTY     115.00
 line      33540  33568  "1 " 1     0     # line   from  TESLA        115.00 to TH.E.DV.     115.00
 line      33540  33574  "1 " 1     0     # line   from  TESLA        115.00 to LLNL TAP     115.00
 line      33540  33959  "1 " 1     0     # line   from  TESLA        115.00 to TCHRT_T2     115.00
 tran      33540  30625  "3 "       0     # tran   from  TESLA        115.00 to TESLA_D      230.00
0

C2-7 "BELLOTA 115 kV Bus 1 and Bus 2 - CB 100 Failure"
 line      33562  33560  "1 " 1     0     # line   from  BELLOTA      115.00 to LCKFRDJA     115.00
 line      33562  33561  "1 " 1     0     # line   from  BELLOTA      115.00 to BLLTAJCT     115.00
 line      33562  33946  "1 " 1     0     # line   from  BELLOTA      115.00 to RVRBK J1     115.00
 tran      33562  33809  "1 "       0     # tran   from  BELLOTA      115.00 to BLLTA 1M      13.20
#
 line      33562  33558  "1 " 1     0     # line   from  BELLOTA      115.00 to LCKFRDJB     115.00
 line      33562  33950  "1 " 1     0     # line   from  BELLOTA      115.00 to RVRBK TP     115.00
 tran      33562  30500  "2 "       0     # tran   from  BELLOTA      115.00 to BELLOTA      230.00
0

C2-8 "STAGG 60 kV Bus Sections D and E - CB 2 Failure"
 line      33704  33693  "1 " 1     0     # line   from  STAGG         60.00 to STAGG JT       60.00
 line      33704  33714  "1 " 1     0     # line   from  STAGG         60.00 to HAMMER         60.00
 tran      33704  30498  "1 "       0     # tran   from  STAGG         60.00 to STAGG-D       230.00
 load      33704  "2 "    0             # load         STAGG         60.00  LOAD==14.56(2.07)
 load      33704  "3 "    0             # load         STAGG         60.00  LOAD==15.61(2.23)
 load      33704  "E2"    0             # load         STAGG         60.00  LOAD==-0.04(0.00)
 load      33704  "E3"    0             # load         STAGG         60.00  LOAD==-0.04(0.00)
#
 line      33704  33706  "1 " 1     0     # line   from  STAGG         60.00 to CNTRY CB       60.00
 line      33704  33706  "2 " 1     0     # line   from  STAGG         60.00 to CNTRY CB       60.00
 tran      33704  30499  "4 "       0     # tran   from  STAGG         60.00 to STAGG-E       230.00
0


 #PG&E 2013 TRANSMISSION EXPANSION PLAN ASSESSMENT
 #SUMPK: CVLY CASE (CENTRAL VALLEY, 1-IN-10 LOAD)
 #AREA 11 12

##########################################################################
#                                                                        #
# 230 KV NERC CATEGORY C5 DCTL OUTAGES                                   #
#                                                                        #
##########################################################################

C5_1 "Stagg-Tesla 230 kV Line & Eight Mile Road-Tesla 230 kV Line"
 line      30489  30624  "1 " 1     0     # line   from  STAGG-J2     230.00   (2) to BRKR  TESLA E      230.00
 line      30489  30499  "1 " 1     0     # line   from  STAGG-J2     230.00   (2) to BRKR  STAGG-E      230.00
#
 line      30622  30624  "1 " 1     0     # line   from  EIGHT MI     230.00  BRKR to BRKR  TESLA E      230.00
0

C5_2 "Eight Mile Road-Stagg 230 kV Line & Eight Mile Road-Tesla 230 kV Line"
 line      30495  30496  "1 " 1     0     # line   from  STAGG        230.00   (2) to BRKR  STAGG-H      230.00
 line      30495  30622  "1 " 1     0     # line   from  STAGG        230.00   (2) to BRKR  EIGHT MI     230.00
#
```

```
 line      30622  30624  "1 " 1      0      # line    from  EIGHT MI     230.00  BRKR to BRKR  TESLA E      230.00
0

C5_3 "Gold Hill-Eight Mile Road 230 kV Line & Eight Mile Road-Lodi Stig 230 kV Line"
 line      30337  30622  "1 " 1      0      # line    from  GOLDHILL     230.00  BRKR to BRKR  EIGHT MI     230.00
#
 line      38000  30622  "1 " 1      0      # line    from  LODI         230.00  BRKR to BRKR  EIGHT MI     230.00
0

C5_4 "Gold Hill-Eight Mile Road 230 kV Line & Gold Hill-Lodi Stig 230 kV Line"
 line      30337  30622  "1 " 1      0      # line    from  GOLDHILL     230.00  BRKR to BRKR  EIGHT MI     230.00
#
 line      30337  38000  "1 " 1      0      # line    from  GOLDHILL     230.00  BRKR to BRKR  LODI         230.00
0

C5_5 "Bellota-Tesla 230 kV Line & Weber-Tesla 230 kV Line"
 line      30500  30624  "1 " 1      0      # line    from  BELLOTA      230.00  BRKR to BRKR  TESLA E      230.00
#
 line      30505  30624  "1 " 1      0      # line    from  WEBER        230.00  BRKR to BRKR  TESLA E      230.00
0

C5_6 "Bellota-Tesla 230 kV Line & Bellota-Weber 230 kV Line"
 line      30500  30624  "1 " 1      0      # line    from  BELLOTA      230.00  BRKR to BRKR  TESLA E      230.00
#
 line      30500  30505  "1 " 1      0      # line    from  BELLOTA      230.00  BRKR to BRKR  WEBER        230.00
0

C5_7 "Tesla-Newark No. 1 230 kV Line & Tesla-Ravenswood 230 kV Line"
 line      30624  30630  "1 " 1      0      # line    from  TESLA E      230.00  BRKR to BRKR  NEWARK D     230.00
#
 line      30624  30703  "1 " 1      0      # line    from  TESLA E      230.00  BRKR to BRKR  RAVENSWD     230.00
0

C5_8 "Delta Switching Yard-Tesla 230 kV Line & Kelso-Tesla 230 kV Line"
 line      30580  30625  "1 " 1      0      # line    from  ALTM MDW     230.00    (3) to BRKR  TESLA D      230.00
 line      30580  38610  "1 " 1      0      # line    from  ALTM MDW     230.00    (3) to BRKR  DELTAPMP     230.00
 tran      30580  33175  "1 "        0      # tran    from  ALTM MDW     230.00    (3) to (1)   ALTAMONT       9.11
#
 line      30569  30570  "1 " 1      0      # line    from  KELSO        230.00  BRKR to (4)    USWP-RLF     230.00
 line      30570  30571  "1 " 1      0      # line    from  USWP-RLF     230.00    (4) to (2)   ALTALAND     230.00
 line      30570  30625  "1 " 1      0      # line    from  USWP-RLF     230.00    (4) to BRKR  TESLA D      230.00
 tran      30570  33836  "1 "        0      # tran    from  USWP-RLF     230.00    (4) to (1)   USWP_#4        9.11
 tran      30571  33832  "1 "        0      # tran    from  ALTALAND     230.00    (2) to (1)   COG.CAPT       9.11
 load      33836  "SG"     0              # load          USWP_#4       9.11  LOAD==0.69(0.44)
 gen       33836  "3 "     0              # gen           USWP_#4       9.11  GEN ==14.19(0.00)
 gen       33832  "1 "     0              # gen           COG.CAPT      9.11  GEN ==4.30(-4.40)
0

C5_9 "Tesla-Tracy No. 1 230 kV Line & Tesla-Tracy No. 2 230 kV Line"
 line      37585  30625  "1 " 1      0      # line    from  TRCY PMP     230.00  BRKR to BRKR  TESLA D      230.00
#
 line      37585  30625  "2 " 1      0      # line    from  TRCY PMP     230.00  BRKR to BRKR  TESLA D      230.00
0

C5_10 "Rancho Seco-Bellota No. 1 230 kV Line & Rancho Seco-Bellota No. 2 230 kV Line"
 line      37016  30500  "1 " 1      0      # line    from  RNCHSECO     230.00  BRKR to BRKR  BELLOTA      230.00
#
 line      30510  30500  "2 " 1      0      # line    from  CAMANCH      230.00    (3) to BRKR  BELLOTA      230.00
 line      30510  39500  "1 " 1      0      # line    from  CAMANCH      230.00    (3) to (1)   CAMANCPP     230.00
 line      30510  37016  "2 " 1      0      # line    from  CAMANCH      230.00    (3) to BRKR  RNCHSECO     230.00
 load      39500  "1 "     0              # load          CAMANCPP      230.00  LOAD==12.30(5.96)
 load      39500  "E1"     0              # load          CAMANCPP      230.00  LOAD==-0.00(0.00)
0

C5_11 "Lockeford-Bellota 230 kV Line & Brighton-Bellota 230 kV Line"
 line      30482  30500  "1 " 1      0      # line    from  LOCKFORD     230.00  BRKR to BRKR  BELLOTA      230.00
#
 line      30348  30500  "1 " 1      0      # line    from  BRIGHTON     230.00  BRKR to BRKR  BELLOTA      230.00
0

C5_12 "Brighton-Bellota 230 kV Line & Rio Oso-Lockeford 230 kV Line"
 line      30348  30500  "1 " 1      0      # line    from  BRIGHTON     230.00  BRKR to BRKR  BELLOTA      230.00
#
 line      30330  30482  "1 " 1      0      # line    from  RIO OSO      230.00  BRKR to BRKR  LOCKFORD     230.00
0

C5_13 "Cottle-Melones 230 kV Line & Bellota-Warnerville 230 kV Line"
 line      38206  37563  "1 " 1      0      # line    from  COTTLE       230.00  BRKR to BRKR  MELONES      230.00
#
 line      30500  30515  "1 " 1      0      # line    from  BELLOTA      230.00  BRKR to BRKR  WARNERVL     230.00
```

APPENDIX B – CAISO CATEGORY C CONTINGENCY LIST

```
0

########################################################################
#                                                                      #
# 115 KV NERC CATEGORY C5 DCTL OUTAGES                                 #
#                                                                      #
########################################################################

C5_14 "Stanislaus-Manteca No.2 115 kV & Stanislaus-Melones-Riverbank Jct 115 kV Lines"
 line     33506  33948  "1 " 1     0     # line   from  STANISLS     115.00  BRKR to (2)   RVRBK J2     115.00
 line     33948  33953  "1 " 1     0     # line   from  RVRBK J2     115.00   (2) to (2)   VLYHMTP2     115.00
 line     33953  33511  "1 " 1     0     # line   from  VLYHMTP2     115.00   (2) to (2)   AVENATP2     115.00
 line     33511  33514  "1 " 1     0     # line   from  AVENATP2     115.00   (2) to BRKR  MANTECA     115.00
#
 line     33503  33936  "1 " 1     0     # line   from  FRGTNTP2     115.00   (2) to (3)   MELNS JB     115.00
 line     33503  33504  "1 " 1     0     # line   from  FRGTNTP2     115.00   (2) to (2)   CATARACT     115.00
 line     33936  33932  "1 " 1     0     # line   from  MELNS JB     115.00   (3) to BRKR  MELONES     115.00
 line     33936  33947  "1 " 1     0     # line   from  MELNS JB     115.00   (3) to BRKR  RIVRBKJT     115.00
 line     33504  33506  "1 " 1     0     # line   from  CATARACT     115.00   (2) to BRKR  STANISLS     115.00
0


C5_15 "Bellota-Riverbank-Melones Sw Sta 115 kV Line & Bellota-Riverbank 115 kV Line"
 line     33562  33950  "1 " 1     0     # line   from  BELLOTA     115.00  BRKR to (3)   RVRBK TP     115.00
 line     33950  33934  "1 " 1     0     # line   from  RVRBK TP     115.00   (3) to (3)   TULLOCH      115.00
 line     33950  33944  "1 " 1     0     # line   from  RVRBK TP     115.00   (3) to BRKR  RVRBANK     115.00
 line     33934  33932  "1 " 1     0     # line   from  TULLOCH      115.00   (3) to BRKR  MELONES     115.00
 tran     33934  34076  "1 "       0     # tran   from  TULLOCH      115.00   (3) to (1)   TULLOCH        6.90
 gen      34076  "1 "    0               # gen          TULLOCH        6.90  GEN ==8.64(1.00)
 gen      34076  "2 "    0               # gen          TULLOCH        6.90  GEN ==8.64(1.00)
#
 line     33562  33946  "1 " 1     0     # line   from  BELLOTA     115.00  BRKR to (2)   RVRBK J1     115.00
 line     33946  33944  "1 " 1     0     # line   from  RVRBK J1     115.00   (2) to BRKR  RVRBANK     115.00
0

C5_16A "Stanislaus-Manteca No. 2 115 kV Line & Riverbank Jct-Ripon 115 kV Line"
 line     33506  33948  "1 " 1     0     # line   from  STANISLS     115.00  BRKR to (2)   RVRBK J2     115.00
 line     33948  33953  "1 " 1     0     # line   from  RVRBK J2     115.00   (2) to (2)   VLYHMTP2     115.00
 line     33953  33511  "1 " 1     0     # line   from  VLYHMTP2     115.00   (2) to (2)   AVENATP2     115.00
 line     33511  33514  "1 " 1     0     # line   from  AVENATP2     115.00   (2) to BRKR  MANTECA     115.00
#
 line     33517  33520  "1 " 1     0     # line   from  RPNJN2       115.00   (2) to BRKR  RIPON        115.00
 line     33517  33951  "1 " 1     0     # line   from  RPNJN2       115.00   (2) to (3)   VLYHMTP1     115.00
 line     33951  33947  "1 " 1     0     # line   from  VLYHMTP1     115.00   (3) to BRKR  RIVRBKJT     115.00
 line     33951  33952  "1 " 1     0     # line   from  VLYHMTP1     115.00   (3) to (1)   VALLY HM     115.00
 load     33952  "1 "    0               # load         VALLY HM     115.00  LOAD==3.86(0.55)
 load     33952  "E1"    0               # load         VALLY HM     115.00  LOAD==-0.02(0.00)
0

C5_16B "Stanislaus-Manteca No. 2 115 kV Line & Manteca-Ripon 115 kV Line"
 line     33506  33948  "1 " 1     0     # line   from  STANISLS     115.00  BRKR to (2)   RVRBK J2     115.00
 line     33948  33953  "1 " 1     0     # line   from  RVRBK J2     115.00   (2) to (2)   VLYHMTP2     115.00
 line     33953  33511  "1 " 1     0     # line   from  VLYHMTP2     115.00   (2) to (2)   AVENATP2     115.00
 line     33511  33514  "1 " 1     0     # line   from  AVENATP2     115.00   (2) to BRKR  MANTECA     115.00
#
 line     33516  33514  "1 " 1     0     # line   from  RPN JNCN      115.00   (2) to BRKR  MANTECA     115.00
 line     33516  33520  "1 " 1     0     # line   from  RPN JNCN      115.00   (2) to BRKR  RIPON        115.00
0

C5_17 "Stanislaus-Melones-Manteca No.1 115 kV & Stanislaus-Manteca No.2 115 kV Lines"
 line     33500  33509  "1 " 1     0     # line   from  MELNS JA     115.00   (3) to (3)   AVENATP1     115.00
 line     33500  33501  "1 " 1     0     # line   from  MELNS JA     115.00   (3) to (3)   FRGTNTP1     115.00
 line     33500  33932  "1 " 1     0     # line   from  MELNS JA     115.00   (3) to BRKR  MELONES     115.00
 line     33509  33510  "1 " 1     0     # line   from  AVENATP1     115.00   (3) to (1)   AVENA        115.00
 line     33509  33514  "1 " 1     0     # line   from  AVENATP1     115.00   (3) to BRKR  MANTECA     115.00
 line     33501  33502  "1 " 1     0     # line   from  FRGTNTP1     115.00   (3) to (1)   FROGTOWN     115.00
 line     33501  33506  "1 " 1     0     # line   from  FRGTNTP1     115.00   (3) to BRKR  STANISLS     115.00
 load     33510  "1 "    0               # load         AVENA        115.00  LOAD==11.55(1.65)
 load     33510  "E1"    0               # load         AVENA        115.00  LOAD==-0.00(0.00)
 load     33502  "1 "    0               # load         FROGTOWN     115.00  LOAD==6.98(1.00)
 load     33502  "2 "    0               # load         FROGTOWN     115.00  LOAD==10.91(1.55)
 load     33502  "E1"    0               # load         FROGTOWN     115.00  LOAD==-0.00(0.00)
 load     33502  "E2"    0               # load         FROGTOWN     115.00  LOAD==-0.00(0.00)
# line   33511 33510  "1 "  1  1      # Switches in Avenan SW 145 to transfer load
# load   33510        "1 "     1      # Restores Load at Avena
 line    33503 33502  "1 "  1  1      #Switches in Frogtown Sw 145 to transfer load
 load    33502        "1 "     1      #Restore load at Frogtown Bk 1
 load    33502        "2 "     1      #Restore load at Frogtown Bk 2
#
 line     33506  33948  "1 " 1     0     # line   from  STANISLS     115.00  BRKR to (2)   RVRBK J2     115.00
```

```
 line     33948  33953  "1 " 1     0     # line   from  RVRBK J2     115.00   (2) to (2)   VLYHMTP2     115.00
 line     33953  33511  "1 " 1     0     # line   from  VLYHMTP2     115.00   (2) to (2)   AVENATP2     115.00
 line     33511  33514  "1 " 1     0     # line   from  AVENATP2     115.00   (2) to BRKR  MANTECA      115.00
0

C5_18 "Tesla-Schulte 115 kV Line No. 1 & Tesla-Schulte 115 kV Line No. 2"
 line     33537  33534  "1 " 1     0     # line   from  SFWY_TP1     115.00   (3) to (1)   SAFEWAY      115.00
 line     33537  33549  "1 " 1     0     # line   from  SFWY_TP1     115.00   (3) to BRKR  SCHULTE      115.00
 line     33537  33541  "1 " 1     0     # line   from  SFWY_TP1     115.00   (3) to (2)   AEC_TP1      115.00
 line     33541  33540  "1 " 1     0     # line   from  AEC_TP1      115.00   (2) to BRKR  TESLA        115.00
 load     33534  "1 "    0             # load         SAFEWAY      115.00  LOAD==3.86(1.98)
 load     33534  "E1"    0             # load         SAFEWAY      115.00  LOAD==-0.00(0.00)
#
 line     33535  33549  "2 " 1     0     # line   from  SFWY_TP2     115.00   (2) to BRKR  SCHULTE      115.00
 line     33535  33543  "1 " 1     0     # line   from  SFWY_TP2     115.00   (2) to (3)   AEC_TP2      115.00
 line     33543  33540  "1 " 1     0     # line   from  AEC_TP2      115.00   (3) to BRKR  TESLA        115.00
 line     33543  33545  "1 " 1     0     # line   from  AEC_TP2      115.00   (3) to (2)   AEC_JCT      115.00
 line     33545  33547  "1 " 1     0     # line   from  AEC_JCT      115.00   (2) to (1)   AEC_300      115.00
 load     33547  "1 "    0             # load         AEC_300      115.00  LOAD==3.00(0.68)
 load     33547  "E1"    0             # load         AEC_300      115.00  LOAD==-0.00(0.00)
0

C5_19 "Tesla-Salado No. 1 115 kV Line & Tesla-Salado-Manteca 115 kV Line"
 line     33540  33961  "1 " 1     0     # line   from  TESLA        115.00  BRKR to (3)   TCHRT_T1     115.00
 line     33961  33960  "1 " 1     0     # line   from  TCHRT_T1     115.00   (3) to (2)   MDSTO CN     115.00
 line     33961  33963  "1 " 1     0     # line   from  TCHRT_T1     115.00   (3) to (2)   TCHRTJCT     115.00
 line     33960  33962  "1 " 1     0     # line   from  MDSTO CN     115.00   (2) to (3)   SALDO TP     115.00
 line     33962  33964  "1 " 1     0     # line   from  SALDO TP     115.00   (3) to BRKR  SALADO       115.00
 line     33962  33967  "1 " 1     0     # line   from  SALDO TP     115.00   (3) to (2)   MILER TP     115.00
 line     33967  33966  "1 " 1     0     # line   from  MILER TP     115.00   (2) to (1)   MILLER       115.00
 line     33963  33569  "1 " 1     0     # line   from  TCHRTJCT     115.00   (2) to (2)   GRANITE      115.00
 line     33569  33968  "1 " 1     0     # line   from  GRANITE      115.00   (2) to (1)   TEICHERT     115.00
 load     33966  "1 "    0             # load         MILLER       115.00  LOAD==1.82(0.88)
 load     33966  "E1"    0             # load         MILLER       115.00  LOAD==-0.00(0.00)
 load     33569  "1 "    0             # load         GRANITE      115.00  LOAD==4.81(1.10)
 load     33569  "E1"    0             # load         GRANITE      115.00  LOAD==-0.00(0.00)
 load     33968  "1 "    0             # load         TEICHERT     115.00  LOAD==7.31(6.45)
 load     33968  "E1"    0             # load         TEICHERT     115.00  LOAD==-0.00(0.00)
#
 line     33514  33970  "1 " 1     0     # line   from  MANTECA      115.00  BRKR to (3)   INGRM C.     115.00
 line     33970  33959  "1 " 1     0     # line   from  INGRM C.     115.00   (3) to (2)   TCHRT_T2     115.00
 line     33970  33965  "1 " 1     0     # line   from  INGRM C.     115.00   (3) to (2)   SALADO J     115.00
 line     33959  33540  "1 " 1     0     # line   from  TCHRT_T2     115.00   (2) to BRKR  TESLA        115.00
 line     33965  33964  "1 " 1     0     # line   from  SALADO J     115.00   (2) to BRKR  SALADO       115.00
 load     33970  "1 "    0             # load         INGRM C.     115.00  LOAD==1.91(0.93)
 load     33970  "E1"    0             # load         INGRM C.     115.00  LOAD==-0.00(0.00)
0

C5_20 "Schulte-Kasson-Manteca 115 kV Line & Tesla-Salado-Manteca 115 kV Line"
 line     33514  33526  "1 " 1     0     # line   from  MANTECA      115.00  BRKR to (3)   KSSN-JC1     115.00
 line     33526  33528  "1 " 1     0     # line   from  KSSN-JC1     115.00   (3) to BRKR  KASSON       115.00
 line     33526  33533  "1 " 1     0     # line   from  KSSN-JC1     115.00   (3) to (2)   OWENSTP2     115.00
 line     33533  33549  "2 " 1     0     # line   from  OWENSTP2     115.00   (2) to BRKR  SCHULTE

#
 line     33514  33970  "1 " 1     0     # line   from  MANTECA      115.00  BRKR to (3)   INGRM C.     115.00
 line     33970  33959  "1 " 1     0     # line   from  INGRM C.     115.00   (3) to (2)   TCHRT_T2     115.00
 line     33970  33965  "1 " 1     0     # line   from  INGRM C.     115.00   (3) to (2)   SALADO J     115.00
 line     33959  33540  "1 " 1     0     # line   from  TCHRT_T2     115.00   (2) to BRKR  TESLA        115.00
 line     33965  33964  "1 " 1     0     # line   from  SALADO J     115.00   (2) to BRKR  SALADO       115.00
 load     33970  "1 "    0             # load         INGRM C.     115.00  LOAD==1.91(0.93)
 load     33970  "E1"    0             # load         INGRM C.     115.00  LOAD==-0.00(0.00)
0

C5_21 "Schulte-Kasson-Manteca 115 kV Line & Manteca-Vierra 115 kV Line"
 line     33514  33526  "1 " 1     0     # line   from  MANTECA      115.00  BRKR to (3)   KSSN-JC1     115.00
 line     33526  33528  "1 " 1     0     # line   from  KSSN-JC1     115.00   (3) to BRKR  KASSON       115.00
 line     33526  33533  "1 " 1     0     # line   from  KSSN-JC1     115.00   (3) to (2)   OWENSTP2     115.00
 line     33533  33549  "2 " 1     0     # line   from  OWENSTP2     115.00   (2) to BRKR  SCHULTE
#
 line     33518  33514  "1 " 1     0     # line   from  VIERRA       115.00  BRKR to BRKR  MANTECA      115.00
0

C5_22 "Stockton 'A'-Lockeford-Bellota Nos. 1 & 2 115 kV Lines"
 line     33556  33555  "1 " 1     0     # line   from  STN COGN     115.00   (3) to BRKR  STKTON A     115.00
 line     33556  33560  "1 " 1     0     # line   from  STN COGN     115.00   (3) to (2)   LCKFRDJA     115.00
 line     33556  33958  "1 " 1     0     # line   from  STN COGN     115.00   (3) to (2)   CPC STCN     115.00
 line     33560  33562  "1 " 1     0     # line   from  LCKFRDJA     115.00   (2) to BRKR  BELLOTA      115.00
 tran     33958  33814  "1 "       0     # tran   from  CPC STCN     115.00   (2) to (1)   CPC STCN      12.47
 load     33555  "4 "    0             # load         STKTON A     115.00  LOAD==22.77(3.25)
```

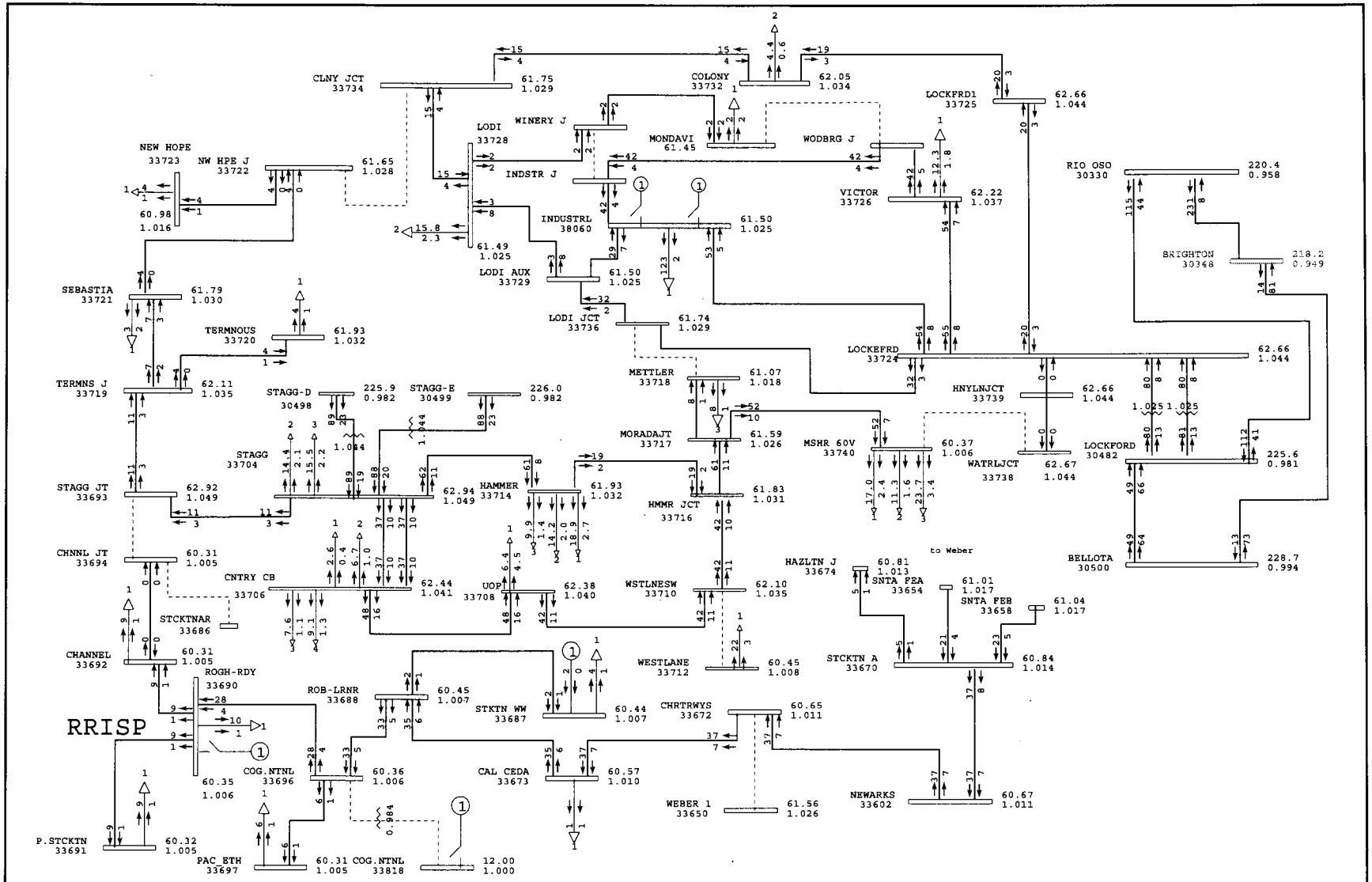
```
 load     33555  "5 "    0              # load         STKTON A     115.00  LOAD==19.97(2.85)
 load     33555  "E4"    0              # load         STKTON A     115.00  LOAD==-0.00(0.00)
 load     33555  "E5"    0              # load         STKTON A     115.00  LOAD==-0.00(0.00)
 load     33814  "SG"    0              # load         CPC STCN      12.47  LOAD==5.06(1.15)
 gen      33814  "1 "    0              # gen          CPC STCN      12.47  GEN ==41.60(5.54)
 line  33555 33553  "1 "  1  1      # Switches in Stockton 'A' SW 177 to transfer load
 load  33555        "4 "     1      # Restore Load at Stockton 'A' Bk 4
 load  33555        "5 "     1      # Restore Load at Stockton 'A' Bk 5
#
 line     33552  33553  "1 " 1     0     # line   from  STCKTNJB     115.00   (2) to BRKR  STKTON B     115.00
 line     33552  33590  "1 " 1     0     # line   from  STCKTNJB     115.00   (2) to (2)   KYOHOTAP     115.00
 line     33590  33558  "1 " 1     0     # line   from  KYOHOTAP     115.00   (2) to (3)   LCKFRDJB     115.00
 line     33558  33562  "1 " 1     0     # line   from  LCKFRDJB     115.00   (3) to BRKR  BELLOTA      115.00
 line     33558  33564  "1 " 1     0     # line   from  LCKFRDJB     115.00   (3) to BRKR  LOCKFORD     115.00
 load     33553  "3 "    0              # load         STKTON B     115.00  LOAD==26.13(3.73)
 load     33553  "E3"    0              # load         STKTON B     115.00  LOAD==-0.00(0.00)
 line  33555 33553  "1 "  1  1      # Switches in Stockton 'A' SW 177 to transfer load
 load  33553        "3 "     1      # Restore Load at Stockton 'A' Bk  3
0

##########################################################################
#                                                                        #
# 60 KV NERC CATEGORY C5 DCTL OUTAGES                                    #
#                                                                        #
##########################################################################

C5_23 "Valley Springs-Martell 60 kV Line Nos. 1 & 2"
 line     33610  33619  "1 " 1     0     # line   from  VLLY SPS      60.00  BRKR to (3)   AMFOR_SW      60.00
 line     33619  33616  "1 " 1     0     # line   from  AMFOR_SW      60.00   (3) to BRKR  MARTELL      60.00
 line     33619  33620  "1 " 1     0     # line   from  AMFOR_SW      60.00   (3) to (1)   AM FORST      60.00
 load     33616  "1 "    0              # load         MARTELL      60.00  LOAD==15.87(2.26)
 load     33616  "E1"    0              # load         MARTELL      60.00  LOAD==-0.00(0.00)
 load     33620  "1 "    0              # load         AM FORST     60.00  LOAD==1.95(1.56)
 load     33620  "E1"    0              # load         AM FORST     60.00  LOAD==-0.00(0.00)
#
 line     33610  33634  "1 " 1     0     # line   from  VLLY SPS      60.00  BRKR to (3)   PRDESWS       60.00
 line     33634  33626  "1 " 1     0     # line   from  PRDESWS       60.00   (3) to (3)   TAPP1009      60.00
 tran     33634  33846  "1 "       0     # tran   from  PRDESWS       60.00   (3) to (1)   PRDE 1-3       7.20
 line     33626  33622  "1 " 1     0     # line   from  TAPP1009      60.00   (3) to (2)   CLAY          60.00
 line     33626  33628  "1 " 1     0     # line   from  TAPP1009      60.00   (3) to (2)   RPSP1009      60.00
 line     33622  33623  "1 " 1     0     # line   from  CLAY          60.00   (2) to (3)   INE_TP        60.00
 line     33623  33617  "1 " 1     0     # line   from  INE_TP        60.00   (3) to (1)   MARTELTP      60.00
 line     33623  33624  "1 " 1     0     # line   from  INE_TP        60.00   (3) to (1)   INE PRSN      60.00
 tran     33628  33816  "1 "       0     # tran   from  RPSP1009      60.00   (2) to (1)   RPSP1009      13.80
 load     33622  "1 "    0              # load         CLAY         60.00  LOAD==8.88(1.26)
 load     33622  "2 "    0              # load         CLAY         60.00  LOAD==7.73(1.10)
 load     33622  "E1"    0              # load         CLAY         60.00  LOAD==-0.00(0.00)
 load     33622  "E2"    0              # load         CLAY         60.00  LOAD==-0.00(0.00)
 load     33624  "1 "    0              # load         INE PRSN     60.00  LOAD==7.14(1.01)
 load     33624  "E1"    0              # load         INE PRSN     60.00  LOAD==-0.00(0.00)
 load     33816  "ss"    0              # load         RPSP1009     13.80  LOAD==2.60(1.44)
 gen      33816  "1 "    0              # gen          RPSP1009     13.80  GEN ==18.40(3.41)
0

end
```

Appendix C

Power Flow Plots

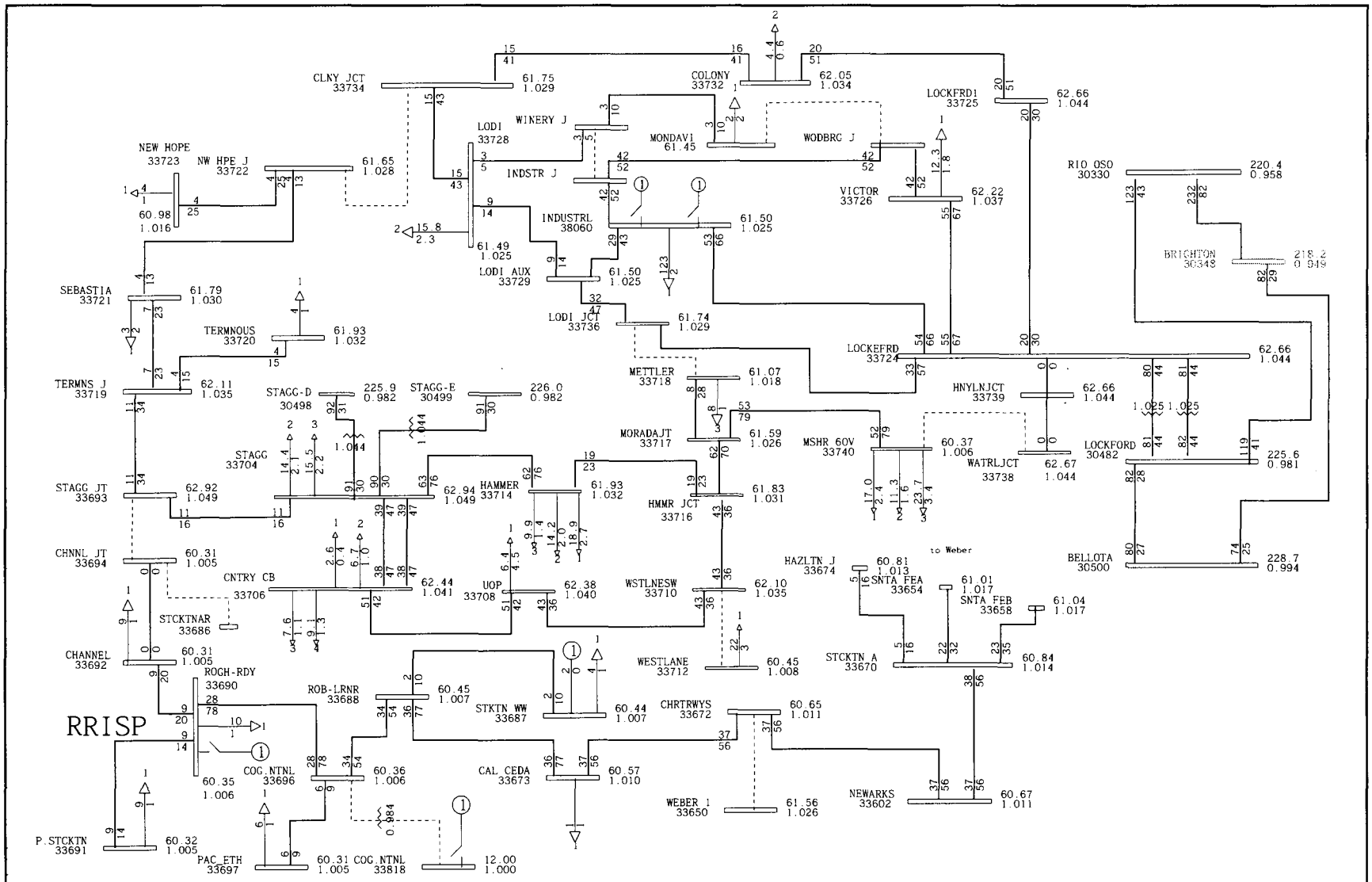
System Impact Study Power Flow Plots

Plot	Description
Plot #101	2015 Summer Peak Pre-Project: Normal Conditions (MW/MVAr)
Plot #102	2015 Summer Peak Pre-Project: Normal Conditions (MVA/% Rate)
Plot #103	2015 Summer Peak Post-Project: Normal Conditions (MW/MVAr)
Plot #104	2015 Summer Peak Post-Project: Normal Conditions (MVA/% Rate)
Plot #105	2015 Summer Off Peak Pre-Project: Normal Conditions (MW/MVAr)
Plot #106	2015 Summer Off Peak Pre-Project: Normal Conditions (MVA/% Rate)
Plot #107	2015 Summer Off Peak Post-Project: Normal Conditions (MW/MVAr)
Plot #108	2015 Summer Off Peak Post-Project: Normal Conditions (MVA/% Rate)



General Electric International, Inc. PSLF Program Mon Sep 23 08:52:22 2013 cases\sumpk\2015sumpk-rrisp-pre.sav

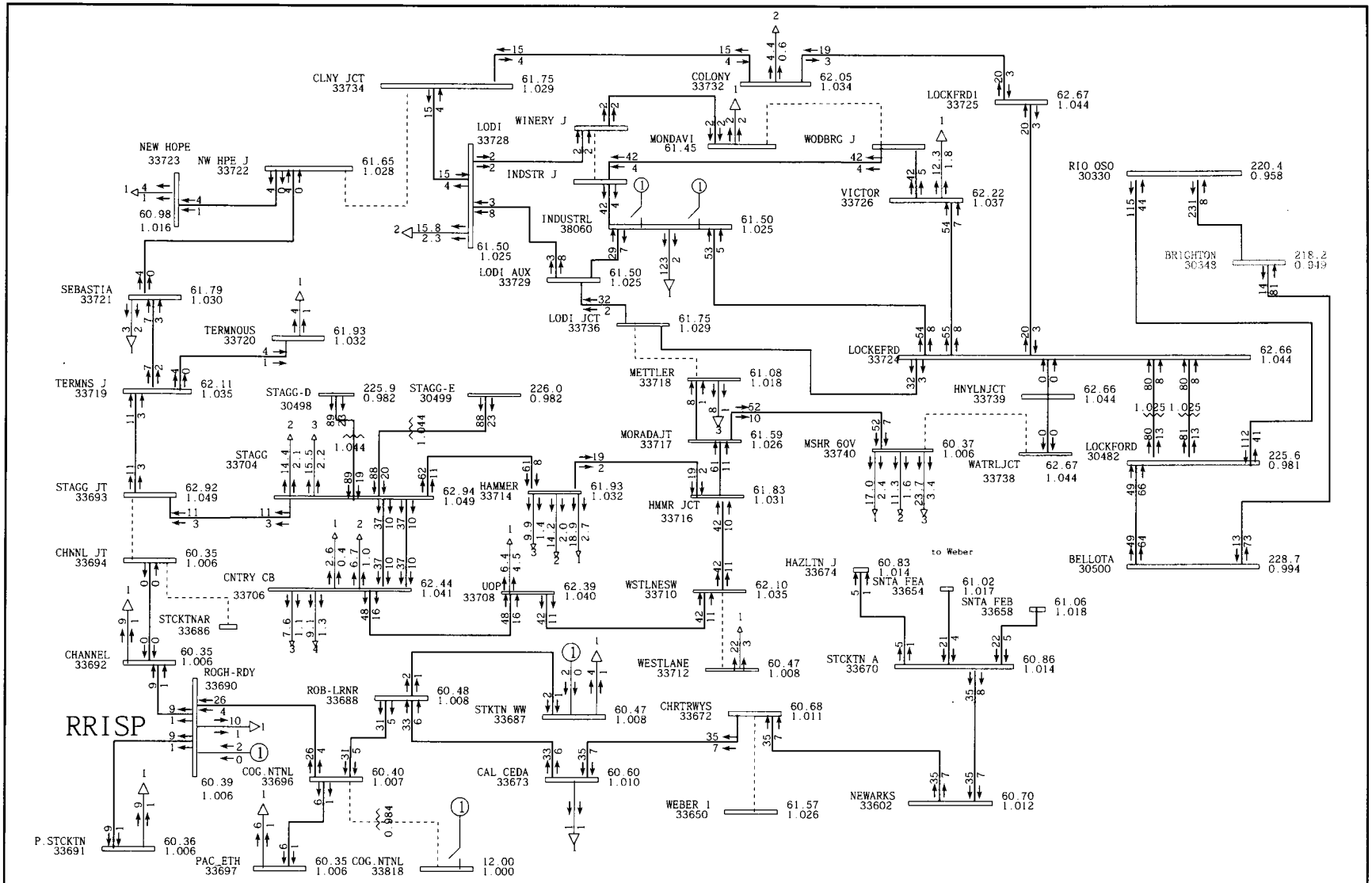
PG&E 2013 CASE SERIES: 2015 Central Valley Summer Peak (1-in-10 ld)	Plot 101: Normal Conditions	MW/MVAR
PATH15=-1685 MW(S-N) PATH26= 4046 MW(N-S) PDCI= 0 MW(N-S) COI= 4794 MW(N-S)		rrisp.drw
Rough and Ready Island Solar Project SIS1 - 2015 Summer Peak Pre-Project		Rating = 1



General Electric International, Inc. PSLF Program Mon Sep 23 08:52:22 2013 cases\sumpk\2015sumpk-rrisp-pre.sav

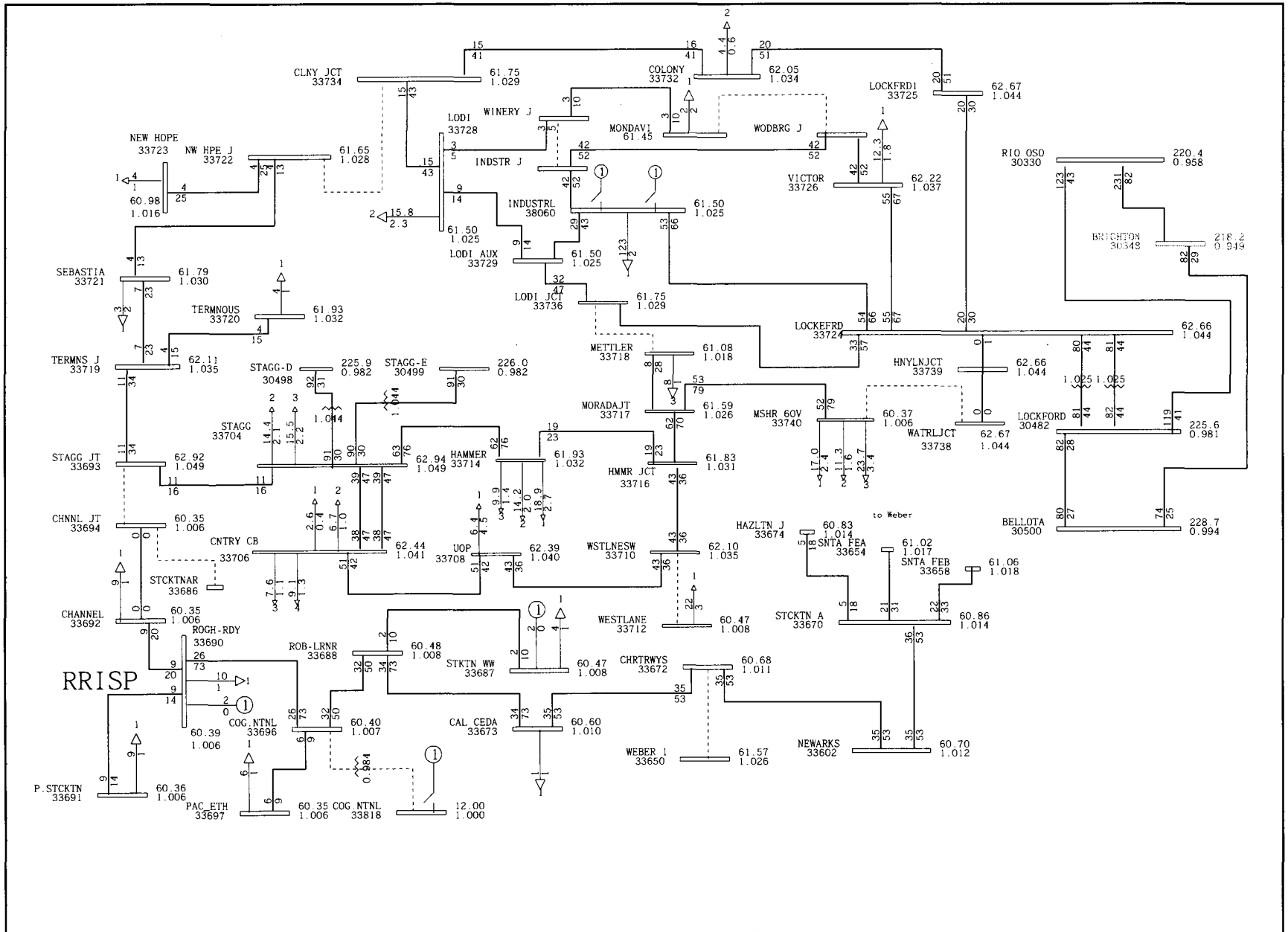
Pacific Gas and Electric Company	PG&E 2013 CASE SERIES: 2015 Central Valley Summer Peak (1-in-10 1d) PATH15=-1685 MW(S-N) PATH26= 4046 MW(N-S) PDCI= 0 MW(N-S) COI= 4794 MW(N-S) Rough and Ready Island Solar Project SIS1 - 2015 Summer Peak Pre-Project	Plot 102: Normal Conditions

MVA/%rate
rrisp.drw
Rating = 1



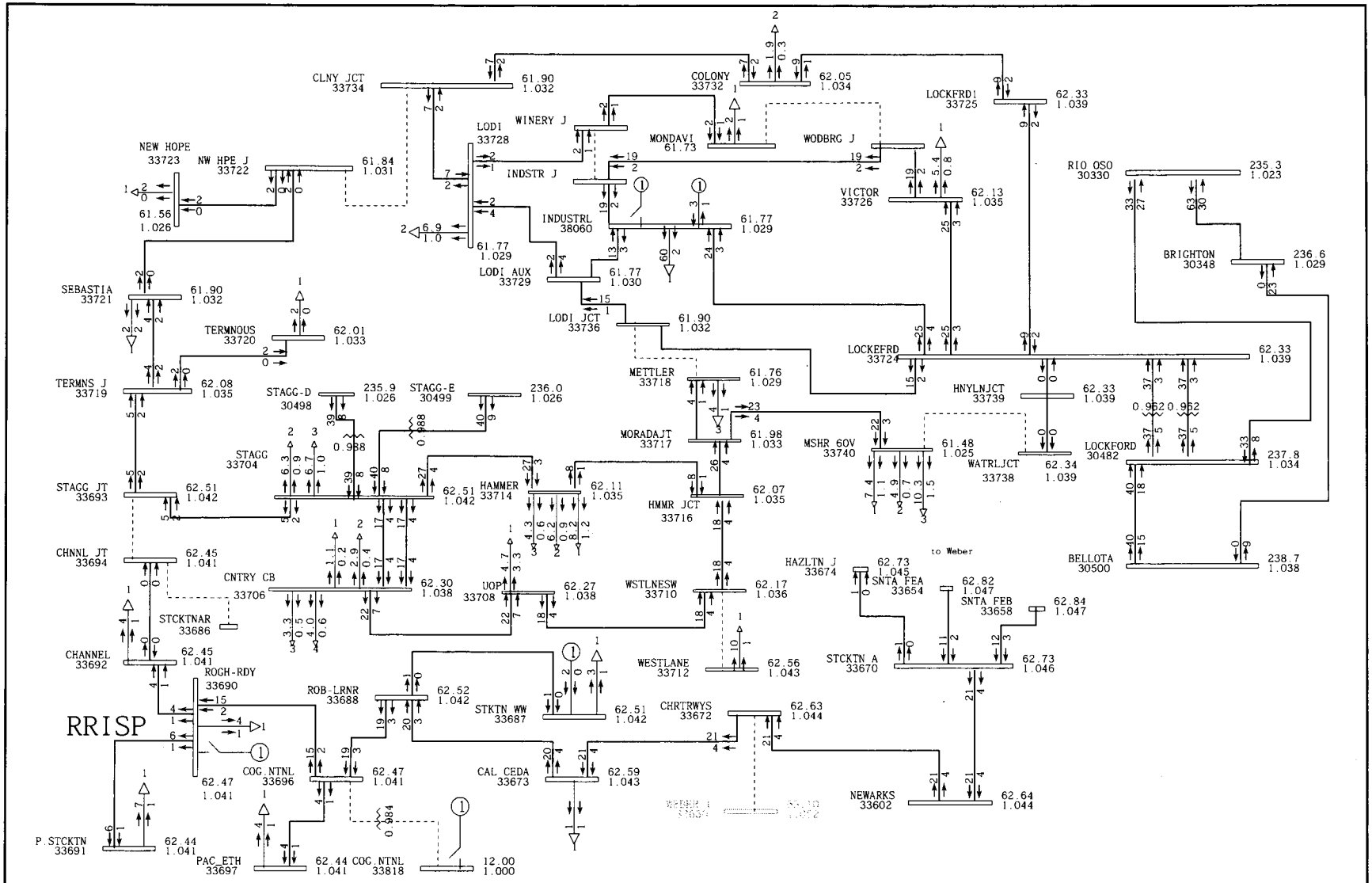
General Electric International, Inc. PSLF Program Mon Sep 23 08:52:22 2013 cases\sumpk\2015sumpk-rrisp-pst.sav

PG&E 2013 CASE SERIES: 2015 Central Valley Summer Peak (1-in-10 1d)	Plot 103: Normal Conditions	MW/MVAR
PATH15=-1687 MW(S-N) PATH26= 4046 MW(N-S) PDCI= 0 MW(N-S) COI= 4794 MW(N-S)		rrisp.drw
Rough and Ready Island Solar Project SIS1 - 2015 Summer Peak Post-Project		Rating = 1



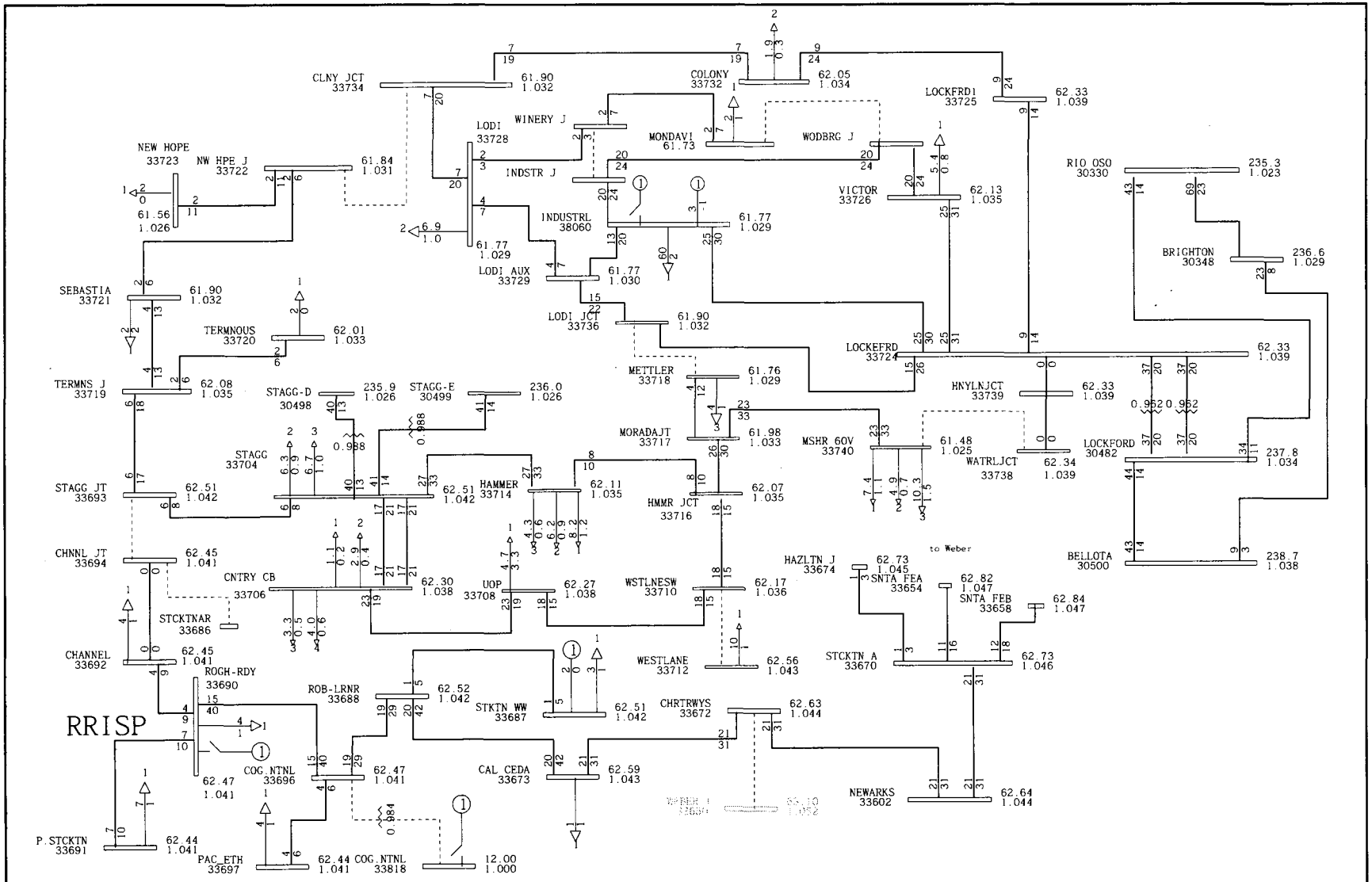
General Electric International, Inc. PSLF Program Mon Sep 23 08:52:23 2013 cases\sumpk\2015sumpk-rrisp-pst.sav

PG&E 2013 CASE SERIES: 2015 Central Valley Summer Peak (1-in-10 1d)	Plot 104: Normal Conditions	MVA/%rate
PATH15=-1687 MW(S-N) PATH26= 4046 MW(N-S) PDCI= 0 MW(N-S) COI= 4794 MW(N-S)		rrisp.drw
Rough and Ready Island Solar Project SIS1 - 2015 Summer Peak Post-Project		Rating = 1



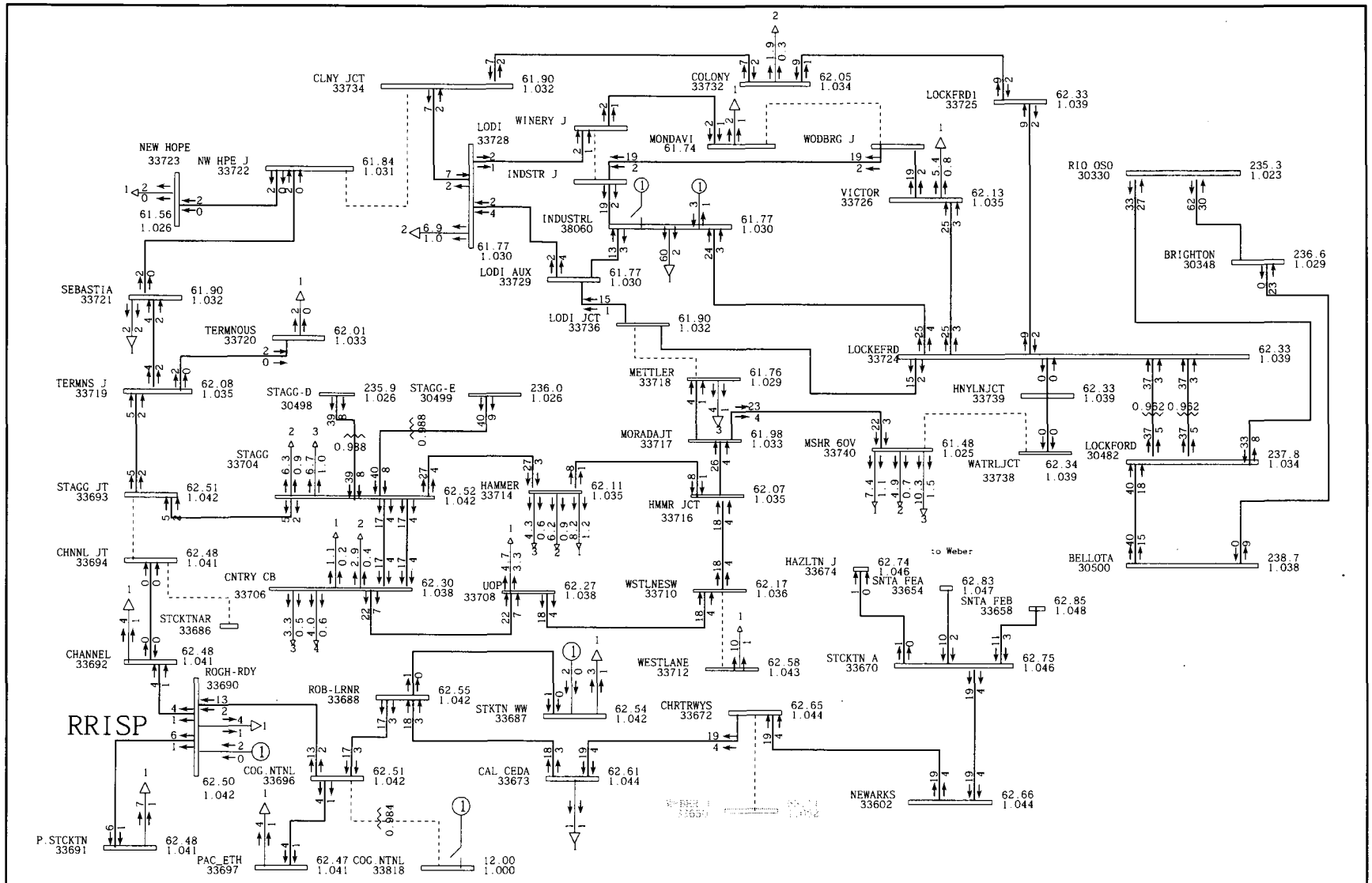
General Electric International, Inc. PSLF Program Mon Sep 23 08:52:23 2013 cases\sumop\2015sumop-rrisp-pre.sav

Pacific Gas and Electric Company	PG&E 2013 CASE SERIES: 2015 System Summer Off Peak Truncated Case PATH15= 4948 MW(S-N) PATH26= -996 MW(N-S) PDCI= 0 MW(N-S) COI=-3023 MW(N-S) Rough and Ready Island Solar Project SISI - 2015 Summer Off Peak Pre-Project	Plot 105: Normal Conditions	MW/MVAR rrisp.drw Rating = 1



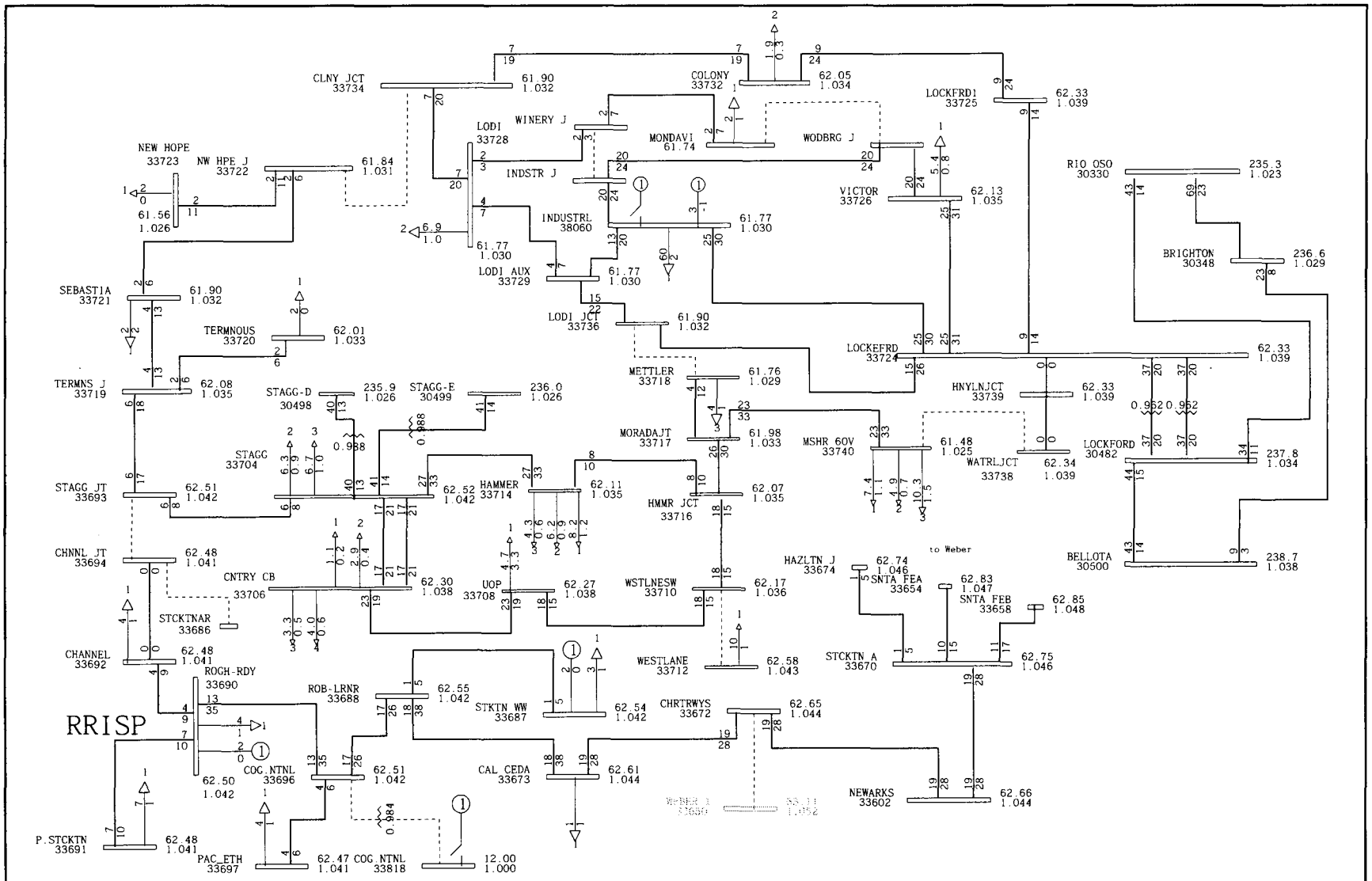
General Electric International, Inc. PSLF Program Mon Sep 23 08:52:23 2013 cases\sumop\2015sumop-rrisp-pre.sav

PG&E 2013 CASE SERIES: 2015 System Summer Off Peak Truncated Case PATH15= 4948 MW(S-N) PATH26= -996 MW(N-S) PDCI= 0 MW(N-S) COI=-3023 MW(N-S) Rough and Ready Island Solar Project SIS1 - 2015 Summer Off Peak Pre-Project	Plot 106: Normal Conditions	MVA/%rate rrisp.drw Rating = 1



General Electric International, Inc. PSLF Program Mon Sep 23 08:52:23 2013 cases\sumop\2015sumop-rrisp-pst.sav

Pacific Gas and Electric Company	PG&E 2013 CASE SERIES: 2015 System Summer Off Peak Truncated Case PATH15= 4946 MW(S-N) PATH26= -996 MW(N-S) PDCI= 0 MW(N-S) COI=-3023 MW(N-S) Rough and Ready Island Solar Project SIS1 - 2015 Summer Off Peak Post-Project	Plot 107: Normal Conditions	MW/MVAR rrisp.drw Rating = 1



General Electric International, Inc. PSLF Program Mon Sep 23 08:52:23 2013 cases\sumop\2015sumop-rrisp-pst.sav

	PG&E 2013 CASE SERIES: 2015 System Summer Off Peak Truncated Case	Plot 108: Normal Conditions
	PATH15= 4946 MW(S-N) PATH26= -996 MW(N-S) PDCI= 0 MW(N-S) COI=-3023 MW(N-S)	MVA/%rate
	Rough and Ready Island Solar Project SIS1 - 2015 Summer Off Peak Post-Project	rrisp.drw
		Rating = 1

Appendix D

Preliminary Protection Requirements

Preliminary Protection Requirements

Port of Stockton - Rough & Ready Island Solar Project

Updated 12/10/2013

Attached are the System Impact Study Preliminary Protection Requirements for the Port of Stockton 2 MW Solar Non-Export Interconnection project having an online date of December 2014.

These protection requirements and fault duty impacts are based on the existing PG&E transmission system and have been updated at the customer's request for a Non-Export interconnection at the Port of Stockton 60kV bus that is tapped off of the Rough & Ready 60kV tap line.

System Impact Study Preliminary Protection Requirements – Port of Stockton 2MW Solar Project - 2014:

Assumptions:
These protection requirements and fault duty impacts are based on the existing PG&E transmission system with the installation of a 2 MW generator connection on the Port of Stockton 12.47 kV Bus. These requirements have been updated to accommodate the customer's request to have a Non-Export interconnection and are limited to the modifications at the Port of Stockton and PG&E Substations to protect PG&E facilities with the generation interconnected. The PG&E Transmission Interconnection Handbook, section G2, should be referenced for further detail with respect to these requirements. Protection for generating equipment beyond that required in the Interconnection Handbook is at the Generator's discretion.

The protection requirements are based on the description provided in the System Impact Study Plan and other subsequent emails.

1. The proposed point of interconnection at the 60kV Port of Stockton bus shall be Non-Export supervised by under power relaying.
2. The proposed generation is a 2 MW, Solar-Xantrex Model connected to the Port of Stockton 12.47 kV feeder. There are no details as to whether this might be comprised of an array of small inverters and possibly a step up transformer to get to the 12.47kV connection voltage.
3. The generation will be connected to the PG&E 60kV system, off the Rough and Ready 60KV tap line, via the existing Port of Stockton 60KV Delta /12.47kV Grounded Wye, 32 MVA customer owned transformer. This

interconnection point is located in the vicinity of the existing PG&E Rough and Ready substation.

4. The Rough and Ready 60kV tap line, is normally connected to the Stockton A #1 60KV line which is fed from Stockton A CB 22. The Rough and Ready 60KV tap can and is transferred to the Stagg CB 42 or the Weber CB 22 breakers under switching conditions that may last months at a time.
5. It is worth mentioning that the DTE Stockton/Cogen National/POSDEF 44 MW Cogen and the Stockton Wastewater 1.5 MW Cogen plants are also connected off the Stockton A #1 60kV line.

PG&E 60kV Source Substations:
There are no anticipated protection impacts or work at the existing PG&E Source substations for this Non-Export interconnection.

Base information and assumptions:
The Basic information is based on the values provided by the customer and the existing PG&E Transmission system:

- Interconnection shall be Non-Export.
- Port of Stockton existing substation transformer: 60.0 kV Delta / 12.47kV GY, 25.0 / 32.0 MVA with a ZHL1=7.89% at 25 MVA rating.
- The 2.0 MVA , 12.47kV generator was modeled as a current source assuming 130% maximum load current using the following impedance values;
- Xd = 0.02 pu
- Xd'= 0.02 pu
- Xd"= 0.02 pu
- X2 = 0.02 pu
- X0 = 999 pu
- Current limit of 120 amps @ 12.47kV

This project causes the Port of Stockton 60KV 3ph fault duty to increase by 24A and the SLG fault current to increase by 5A. The circuit breakers must be appropriately rated.

DTT Requirements:
The customer has elected a Non-Export interconnection that will be supervised by under power relay tripping so NO direct transfer trip (DTT) for the PG&E source substation breakers is required to be installed.

Port of Stockton Under Power Relay Requirements:
Install redundant three phase under power relaying on the 12kV side of the Port of Stockton Transformer. These relays will detect an under power condition associated with the loss of the 60kV source to the substation and will trip the generation offline locally within the substation.

Port of Stockton 60kV CB 62 Line Ground Fault Protection:
Because of the Port of Stockton transformer has a high side delta winding, ground overcurrent relays cannot provide 60 kV line to ground fault protection. A 3Vo (47) voltage sensing ground protection scheme will have to be installed to trip the Port of Stockton CB 62 for 60kV line ground faults. This will necessitate the installation of a three phase set of 60kV Potential transformers to create the 3Vo quantity for the relays. The existing revenue metering potential transformers may not be used for relaying schemes.

Voltage and Frequency Protection:

Relays providing multiple PG&E functions must have the proper level of redundancy per the PG&E Interconnection Handbook section G2.

In addition to the 3Vo (47) protection above, PG&E requires Undervoltage (27), Overvoltage (59), Over and Under Frequency (81-O/U) protection be installed at the Port of Stockton 60kV bus that will either trip CB 62 or trip a local 12kV generator breaker.

The PG&E Interconnection Handbook table G2-1b shows the generic protection functions required for the installation of a paralleled generator and table G2-4 shows the Utility Grade relays (required) that PG&E approves for use.

Protection at the Port of Stockton Generation Plant / Plant 12KV Breaker:

Protection inside the Port of Stockton System is at the sole discretion of the Port of Stockton and should conform to good utility practice.

The Port of Stockton may choose to have **27 , 59, 81O/U** at their 12KV generator plant at their discretion, but PG&E only requires this protection at the 60KV breaker CB 62 point of interconnection.

1. **Fault Duty Table**

Sys. Pro. Results 9-14-13 Proposed Project: Port of Stockton			Short Circuit Currents on Selected Busses for the Proposed Project (AMPS)			
			Case 1		Case 2	
			Base Case System		Case 1 + Addition of Proposed Project	
	Bus Name	kV	3LG (A)	1LG (A)	3LG (A)	1LG (A)
1	Port of Stockton	60 kV	6823A	5262A	6847A	5267A

Protection time estimate GIHB Customer Submittals Review- 160 hours:

- Walkdowns, print review, technician support and updating protection records, files and databases, and third party Submittal review.

NEXT ENERGY CONCEPTS

P.O. Box 20245
SAN JOSE, CALIFORNIA 95160
PH: 1-949-632-0499, 1-408-717-0462

March 30, 2012

DRAFT

Mr. Steve Escobar
Deputy Port Director
Port of Stockton
220 West Washington Street
Stockton CA 95201

Re: Offer to develop a Renewable Power System – Port of Stockton West Complex Solar (WCS)

Dear Steve,

Next Energy Concepts, LLC ("NEC") of San Jose, California proposes to develop a Solar PV system for the benefit of the Stockton Port District. This one-megawatt solar array will take full advantage of the engineering and development work accomplished by NEC in 2010 and 2011 and result in the lowest cost alternative for the Port. Our development plan will ensure both that the installation work is performed by Stockton based companies utilizing local labor and an aggressive competitive process for the bulk of the solar hardware to assure the Port Management that the best price for performance and quality is achieved.

Conceptually, the 1MW array will be installed on two or three of the West Complex warehouses as originally identified in the Rough & Ready Solar (RRS) project plan of 2011. Design and permitting will take full advantage of all work done for RRS and therefore reduce the development time and cost significantly. The installed generating capacity will match the renewable requirements that the Port must achieve and therefore can be installed in stages starting in 2013.

The local contractors in this program will include companies with the required expertise that are Stockton based and have ongoing relationships with the Port. Established working relationships and experience with the structures and procedures at the Port will result in the least cost installation. Participants in the project would likely include:

Next Energy Concepts	Developer/Owner
Blach Construction	General Contractor
Roof Rangers	Solar Array Installation
Bockman and Woody	Electrical Installation

NEC will manage competitive bidding for the solar arrays with the assistance of Blach Construction. Blach has detailed experience in specifying and installing many solar PV systems for Northern California schools and colleges. Up to 65% of the total cost of the system will be the solar collector hardware. All reputable suppliers will be invited to participate in a competitive process that achieves the best combination of lowest cost and guaranteed performance.

This three pronged approach of building on work accomplished in 2011, utilizing local contractors familiar with the Port and an aggressive competitive hardware procurement program will assure the Port the best possible renewable power supply at the lowest cost.

This design and installation process is equally applicable to a project funded and owned by the Port or one in which NEC enters into an Energy Supply Agreement (ESA) with the Port and privately finances the project based on that ESA.

General Information Regarding NEC

Next Energy Concepts is a California Limited Liability Company formed in 2008 to develop Renewable, Hybrid Renewable and Combined Heat and Power (CHP) systems. NEC has extensive experience in power generation including direct involvement in Greenfield development, mergers and acquisitions, construction management, O&M and accounting and administration.

- Richard Zahner: 32 years experience with Bechtel, Calpine, Diamond Energy, and others.
- Tom Glymph: 32 years experience with Calpine, Destec and others.
- Chuck Clark: 35 years experience with Calpine, Century Contractors West, Inc and others.

We look forward to our meeting on the 30th to discuss this proposal and the economic benefits of both approaches.

Sincerely,

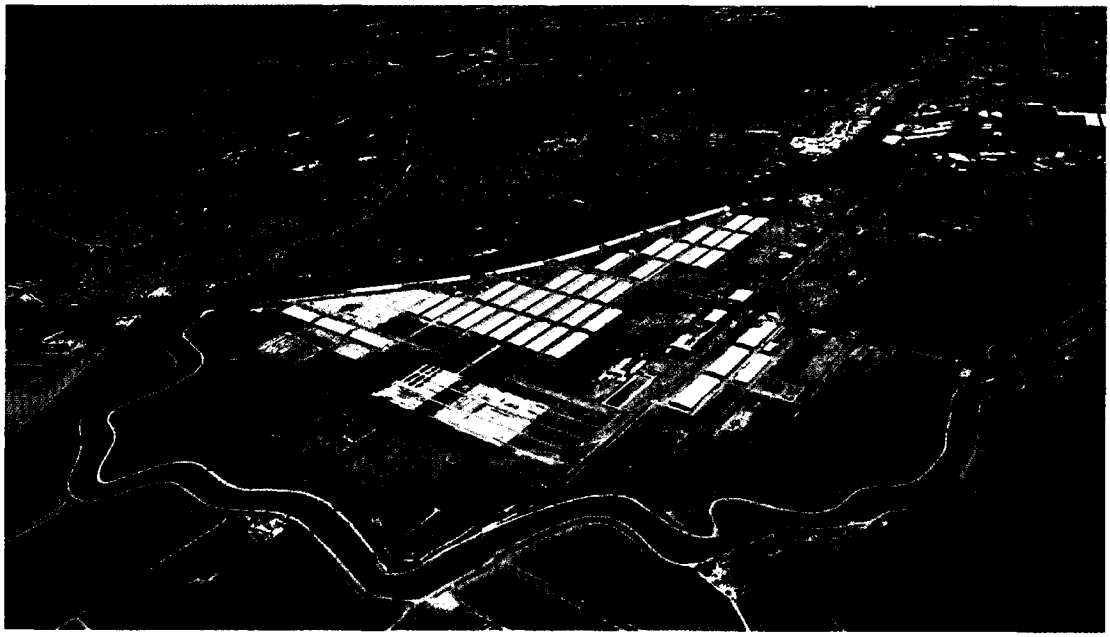
Richard R Zahner
Principal
Next Energy Concepts, LLC

cc: T. Glymph
C. Clark

General Description of West Complex Solar

Project:	West Complex Solar
Proposed Equipment:	TBD via Solicitation Process
Net Power Output:	1 MW
Location:	Rough & Ready Island (West Complex), Port of Stockton, CA
Interconnection Delivery Point:	Port Distribution System
Commercial Operations Date:	2nd Quarter 2013

Project Site – West Complex



PPA – POWER PURCHASE AGREEMENT

20 years, 3% annual escalator

2 MW system:

- Starting rate $0.110/kWh

500 kW system:

- Starting rate $0.150/kWh

PURCHASE PRICE (TURNKEY)

** for information purposes only*

2 MW system:

- $5,962,000

500 kW system:

- $1,734,000

SYSTEM PERFORMANCE

2 MW system:

- Available Generation: 3,444,708 kWh
- Effective Generation: 3,281,859 kWh

* No generation bigger than consumption allowed

500 kW system:

- Available Generation: 861,177 kWh
- Effective Generation: 861,177 kWh

1565 E. Tuolumne Road
Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
chris_k@cornerstoneconsulting.biz

CORNERSTONE CONSULTING

Memo

To: Juan Villanueva

From: Chris Kiriakou

CC: Steve Escobar, Richard Smith, Jeff Kaspar

Date: January 10, 2012

Re: PV Generating Station Schedule

The State has approved a 33% Renewable Portfolio Standard (RPS) that requires all California utilities supply 33% of their retail sales from renewable resources by 2020. In order for the Port to meet the RPS it will require a combination of purchases of Renewable Energy Certificates (RECs) and local renewable generation. The ability to use RECs to meet the RPS is limited and diminishes over time. Photovoltaic generating panels have come down in price significantly from 2 years ago. For these reasons in addition to the significant load growth the Port has been experiencing, now is the time to do some preliminary work necessary to consider the approval and construction of a 1.5 MW PV generating station.

Following is a tentative schedule for the consideration and construction of a 1.5 MW photovoltaic generating station.

Task	Time	Start Task	Complete
1. Prepare single line and technical support	2 Weeks	Nov. 15, 2012	Dec. 1, 2012
2. Notice PG&E and CAISO	1 day	Dec. 2, 2012	Dec. 2, 2012
3. Commence PG&E Studies	6 Months	Dec. 2, 2012	May 31, 2013
4. Prepare 2013/14 budget item	3 Months	Dec. 1, 2012	March 1, 2013
5. Obtain budget approval	4 Months	March 1, 2013	June 30,2013
6. Start Arrangements for Financing	7 Months	March 1, 2013	Sept. 30, 2013
7. Start Bid Documents Preparation	3 Months	July 1, 2013	Sept. 30, 2013
8. Release Bid and Start RFP process	3 Months	Oct. 1, 2013	Dec. 31, 2013
9. Award Bid		January 2, 2014	
10. Start Procurement and Construction	10 Months	January 2, 2014	Oct. 31, 2014
11. Testing	1 Month	Nov. 1, 2014	Nov. 30, 2014
12. Commercial Operation Date			Dec. 31, 2014

This schedule is preliminary and subject to adjustments as required by the Port. The schedule does not include obtain permits from the City of Stockton. We view the project as constructed by the Utility, for the Utility and not for Retail Operation.

HCS ENGINEERING, INC.

CONSULTING ELECTRICAL ENGINEERING

4512 FEATHER RIVER DR. STE. F
STOCKTON, CA 95219
(209) 478-8270
FAX (209) 478-2169

May 31, 2012

Steve Escobar
Port of Stockton
PO Box 2089
Stockton, CA 95201

Re: 500KW Solar PV Electrical System Installation

Dear Steve:

HCS Engineering has designed a variety of solar power systems. We have designed a 20MW system for Spain's RIOS Renewables being constructed in Davis, California. We have designed systems for Target, Schools and Industrial customers. For the City of Stockton, we have served as third plan reviewer for 15 local projects. We have served as the Inspector of Record for the City's PV system at the Delta Water Treatment Plant.

We have developed the following proposal to design a 500 kw Solar PV Electrical System for the Port of Stockton. From our discussions, we have the following basis for design:

A. Power Generation: 500 KW, 480 volt, utility connected.

B. Metering Point: 480 volt at the utility side of the inverter (secondary of a transformer).

C. The inverter would be line interactive. This means if the utility power goes down, the inverter goes off-line.

D. We would monitor power generation from the SCADA system at the powerhouse and have remote control options to turn the system on and off if required.

E. The solar panels would be designed to be rooftop. We would solicitate a Structural Engineer to review the roof structure of the building.

The following is not in the basis of design:

1. Demand tracking systems. The outputs of the inverters won't be designed to ramp up and down to meet the demands of the system.

2. Energy Storage. Battery systems will not be designed.

3. Solar tracking system. The PV panels would be designed to be fixed in place and won't track the sun.

4. Terrestrial PV systems (ground mounted).

Scope of work: To give the Port options, I have broken the proposal down into tasks.

Task 1. Meters and Control and Utility Work
- Design for Solar PV system to be monitored at controlled by the SCADA system at the power house of the substation. This will require the use of a pair of Port

Fiber plant (multimode) from the Substation to the building that the Port selects.
- Design for the remote operations of:
  - Monitoring power generation
  - Remote disconnection of the PV system from the Port grid.
- Outside of any required permit, we would design the utility connections of the inverter and meter into the distribution system.

Task 2A. Complete Design of a Solar PV Generation System
- This option would include complete electrical design of the solar array and producing plans for permit and bid. We would specify the inverters, panels, and show all wiring required for permits by the Port and installation by the Contractor.
- Secure a Structural Engineer to review the building and produce structural calculations.

Task 2B. Performance Design of the Solar PV Generation System
- This option would include a narrative and performance specifications for the design work. This would produce a design build document. The Contractor would then produce his own permit plans, and perform the work.

Task 3. Construction Management
- This task would include the construction management functions of holding bi-weekly meetings, shop drawing review, meeting with the Contractor and City during construction and start up.

Fee Basis

Task 1.	Utility Work and SCADA Monitoring	$3,500
Task 2A.	Complete Solar System Design	$5,500 with Structural
Task 2B.	Performance Design of the System for Design Building	$1,500
Task 3.	Construction Management.	$4,500

Since 2a and 2b are options and 3 is optional, the fee can be broken into a good, better, best.

The good engineering effort is Task 1, 2B and the port does all of the Project Admin for a fee $5,000.

The better engineering effort is Task 1, 2b and 3 for a fee of $10,500.

The best engineering effort is Task 1, 2a, and 3 for a fee of $13,500

The estimated cost of the project is $1.65 million. Solar power is running approximately $3 per kilowatt constructed, plus the utility connections and SCADA.

Please don't hesitate to call if you have any questions.

Sincerely,

HCS Engineering, Inc.

Richard C. Smith, P.E.
Electrical Engineer

HCS ENGINEERING, INC.

CONSULTING ELECTRICAL ENGINEERING

4512 FEATHER RIVER DR. STE. F
STOCKTON, CA 95219
(209) 478-8270
FAX (209) 478-2169

December 29, 2017

Steve Escobar
Port of Stockton
PO Box 2089
Stockton, CA 95201

Re: Port 1500 W Solar PV Plant
Electrical Systems Interconnection Proposal

Dear Steve:

HCS Engineering is pleased to submit this proposal for Electrical Engineering services on the above-mentioned project. For this project, our services will include:

Task 1: Prepare Single Line Diagrams and background materials for PG&E and technical support.

In this task, we will produce the initial drawings required by PG&E for interconnection discussions for the Port Solar Project.

Task 2: Note to PG&E (Cornerstone).

Task 3: Commence PG&E Studies (PG&E).

Task 4: Prepare 2013/2014 Budget Item (Cornerstone).

Task 5: Obtain budget approval (Steve).

Task 6: Arrange for Financing (Steve and Cornerstone).

Task 7: Bid Documents Preparation.

We have developed the following proposal to design a 1500 KW Solar PV Electrical System for the Port of Stockton. From our discussions, we have the following basis for design:

1. Power Generation: (3) 500 KW, 480 volt, utility connected.

2. Metering Point: 480 volt at the utility side of the inverter (secondary of a transformer).

3. The inverter would be line interactive. This means if the utility power goes down, the inverter goes off-line.

4. We would monitor power generation from the SCADA system at the powerhouse and have remote control options to turn the system on and off if required.

5. The solar panels would be designed to be ground. We would solicit a Structural Engineer to design the structure and supports.

6. Demand tracking systems. The outputs of the inverters won't be designed to ramp up and down to meet the demands of the system.

7. Energy Storage. Battery systems will not be designed unless there is a clear indication of an economic advantage to their use for energy not required by load.

The following is not in the basis of design:

1. Solar tracking system. The PV panels would be designed to be fixed in place and won't track the sun.

2. Rooftop PV systems will not be considered.

Sub Task A: Meters and Control and Utility Work:

- Design for Solar PV system to be monitored at controlled by the SCADA system at the power house of the substation. This will require the use of a pair of Port Fiber plant (multimode) from the Substation to the building that the Port selects.
- Designed such that there will be no net export out of the Port's electric system into the PG&E system.
- Design for the remote operations of:
    - Monitoring power generation.
    - Remote disconnection of the PV system from the Port grid.
- Outside of any required permit, we would design the utility connections of the inverter and meter into the distribution system.
- Coordinate with the Port staff in determining final economics of the project.
- If included battery storage would be incorporated into the design.

Subtask B: Research and Report on options for Energy Storage.

Subtask C: Complete Design of a Solar PV Generation System.

- This option would include complete electrical design of the solar array and producing plans for permit and bid. We would specify the inverters, panels, and show all wiring required for permits by the Port and installation by the Contractor.
- We will include a list of approved manufacturers for equipment.
- Secure a Structural Engineer to review the building and produce structural calculations.

Task 8: Release the Bid and Start the RFP Process (Juan).

- We would attend the job walks, answer questions, and review proposals.

Task 9: Award Bid (Juan).

Task 10: Start procurement and construction.

- We would perform the project management, conducting bi-weekly meetings, review submittals and coordinate the relay protection.

Task 11: Testing.

- We would review testing procedures and witness testing.

Task 12: Commercial Operations.

- We would witness the start of operations of the PV plant.

The estimated cost of the project is $56,000.

Please don't hesitate to call if you have any questions.

Sincerely,

HCS Engineering, Inc.

Richard C. Smith, P.E.
Electrical Engineer

HCS ENGINEERING, INC.

CONSULTING ELECTRICAL ENGINEERING

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December 29, 2017
Steve Escobar
Port of Stockton
PO Box 2089
Stockton, CA 95201

Re: Port 1500 W Solar PV Plant
Electrical Systems Interconnection Proposal

Dear Steve:

HCS Engineering is pleased to submit this proposal for Electrical Engineering services on the above-mentioned project. For this project, our services will include:

Task 1: Preliminary Engineering Support
Prepare Single Line Diagrams and background materials for PG&E Notice and technical support.

In this task, we will produce the initial drawings required by PG&E for interconnection discussions for the Port Solar Project.

Assist with technical analysis if required by PG&E as part of the Studies that they may require.

Task 2: Project Costs Estimate and Economics Support
Assist with the preparation of the 2013/2014 Budget for the PV Project including any financial/technical support □

Task 3: Project Detailed Engineering and Optional Energy Storage

We have developed the following proposal to design a 1500 KW Solar PV Electrical System for the Port of Stockton. From our discussions, we have the following basis for design:

1. Power Generation: (3) 500 KW, 480 volt, utility connected.

2. Metering Point: 480 volt at the utility side of the inverter (secondary of a transformer).

3. The inverter would be line interactive. This means if the utility power goes down, the inverter goes off-line.

4. Our Design would monitor power generation from the SCADA system at the powerhouse and have remote control options to turn the system on and off if required.

5. The solar panels would be designed to be ground. We would solicit a Structural Engineer to design the structure and supports.

6. Demand tracking systems. The outputs of the inverters won't be designed to ramp up and down to meet the demands of the system.

7. Energy Storage. Battery systems will not be designed unless there is a clear indication of an economic advantage to their use for energy not required by load. Cornerstone will lead on the Energy Storage economic analysis.

The following is not in the basis of design:

1. Solar tracking system. The PV panels would be designed to be fixed in place and won't track the sun.

2. Rooftop PV systems will not be considered.

Sub Task A: Meters and Control and Utility Work:

1. Preliminary design for Solar PV system to be monitored at controlled by the SCADA system at the power house of the substation. This will require the use of a pair of Port Fiber plant (multimode) from the Substation to the building that the Port selects.
2. Designed such that there will be no net export out of the Port's electric system into the PG&E system.
3. Design for the remote operations of:
    1. Monitoring power generation.
    2. Remote disconnection of the PV system from the Port grid.
    3. Outside of any required permit, we would design the utility connections of the inverter and meter into the distribution system.

4. Coordinate with the Port staff in determining final economics of the project.
5. Incorporation of any PG&E monitoring and/or control requirements

Subtask B: Research and Report on options for Energy Storage.

1. If the Port elects to include battery storage, battery storage control would be incorporated into the project design

Subtask C: Assist with the preparation of the Bid Documents, bidding process and project award.

Subtask D: Complete Design of a Solar PV Generation System.

1. Upon a Port decision to award the bid, this option would include complete electrical design of the solar array and producing plans for permit . We would specify the inverters, panels, and show all wiring required for permits by the Port and installation by the Contractor

2. We will include a list of approved manufacturers for equipment.

3. Secure a Structural Engineer to review the building and produce structural calculations.

Task 4: Construction Engineering, Management and Testing Start procurement, construction, and testing leading to the start of commercial operation.

1. Complete construction engineering and drawings

2. We would perform the project management, conducting bi-weekly meetings, review submittals and coordinate the relay protection.
Testing.

3. We would review testing procedures and witness testing.
Commercial Operations.

4. We would witness the start of operations of the PV plant.

5. Complete as-built drawings, equipment documentation and maintenance requirements documentation including project closeout.

The estimated **total cost of the project is $56,000.** The specific identified tasks are priced as follows.

Task 1: Preliminary Engineering Support $5,000

Task 2: Project Costs Estimate and Economics Support $5,000

Task 3: Project Detailed Engineering and Optional Energy Storage $40,000

Task 4: Construction Engineering, Management and Testing $6,000

At any time, should the Port elect to suspend or cancel the project, it will only be responsible for the effort expended within the current Task.

Please don't hesitate to call if you have any questions.

Sincerely,

HCS Engineering, Inc.

Richard C. Smith, P.E.
Electrical Engineer

HCS ENGINEERING, INC.

CONSULTING ELECTRICAL ENGINEERING

4512 FEATHER RIVER DR. STE. F
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(209) 478-8270
FAX (209) 478-2169

December 29, 2017~~July 25, 2016~~~~November 7, 2012~~

Steve Escobar
Port of Stockton
PO Box 2089
Stockton, CA 95201

Re: 1,500KW Solar PV Electrical System Installation

Dear Steve:

HCS Engineering has designed a variety of solar power systems. We have designed a 20MW system for Spain's RIOS Renewables being constructed in Davis, California. We have designed systems for Target, Schools and Industrial customers. For the City of Stockton, we have served as third plan reviewer for 15 local projects. We have served as the Inspector of Record for the City's PV system at the Delta Water Treatment Plant.

We have developed the following proposal to design a 1500 kw Solar PV Electrical System for the Port of Stockton. From our discussions, we have the following basis for design:

A. Power Generation: (3) 500 KW, 480 volt, utility connected.

B. Metering Point: 480 volt at the utility side of the inverter (secondary of a transformer).

C. The inverter would be line interactive. This means if the utility power goes down, the inverter goes off-line.

D. We would monitor power generation from the SCADA system at the powerhouse and have remote control options to turn the system on and off if required.

E. The solar panels would be designed to be ground. We would solicit a Structural Engineer to design the structure and supports.

F. Demand tracking systems. The outputs of the inverters won't be designed to ramp up and down to meet the demands of the system.

G. Energy Storage. Battery systems will not be designed unless there is a clear indication of an economic advantage to their use for energy not required by load.

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The following is not in the basis of design:

1. Solar tracking system. The PV panels would be designed to be fixed in place and won't track the sun.

2. Rooftop PV systems will not be considered.

Scope of work: To give the Port options, I have broken the proposal down into tasks.

Task 1A. Meters and Control and Utility Work
~~Design for Solar PV system to be monitored at controlled by the SCADA system at the power house of the substation. This will require the use of a pair of Port~~

- Design for Solar PV system to be monitored at controlled by the SCADA system at the power house of the substation. This will require the use of a pair of Port Fiber plant (multimode) from the Substation to the building that the Port selects.
- Designed such that there will be no net export out of the Port's electic system into the PG&E system.
- Design for the remote operations of:
  - Monitoring power generation
  - Remote disconnection of the PV system from the Port grid.
- Outside of any required permit, we would design the utility connections of the inverter and meter into the distribution system.
- Coordinate with the Port staff in determining final economics of the project.
- If included battery storage would be incorporated into the design.

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Task 1B. Research and Report on options for Energy Storage.

Task 2A. Complete Design of a Solar PV Generation System
- This option would include complete electrical design of the solar array and producing plans for permit and bid. We would specify the inverters, panels, and show all wiring required for permits by the Port and installation by the Contractor. We will include a list of approved manufacturers for equipment.
- Secure a Structural Engineer to review the building and produce structural calculations. (What building?)

Task 2B. Performance Design of the Solar PV Generation System
- This option would include a narrative and performance specifications for the design work. This would produce a design build document. The Contractor would then produce his own permit plans, and perform the work.

Task 3. Construction Management
- This task would include the construction management functions of holding bi-weekly meetings, shop drawing review, meeting with the Contractor and City during construction and start up.

Fee Basis

Task 1A.	Utility Work and SCADA Monitoring	$3,500
Task 1B.	Energy Storage Research	$2,500
Task 2A.	Complete Solar System Design	$15,500 w/ Structural
Task 2B.	Performance Design of the System for Design Building	$5,500
Task 3.	Construction Management.	$4,500

Since 2a and 2b are options and 3 is optional, the fee can be broken into a good, better, best.

The good engineering effort is Task 1A, 1B and 2B the port does all of the Project Admin for a fee $11,500.

The better engineering effort is Task 1A, 1B, 2B and 3 for a fee of $16,000.

The best engineering effort is Task 1A, 1B, 2A and 3 for a fee of $26,000

The estimated cost of the project is $1.65 million. Solar power construction estimate are approximately $3 per watt plus the utility connections and SCADA.

Please don't hesitate to call if you have any questions.

Sincerely,

HCS Engineering, Inc.

Richard C. Smith, P.E.
Electrical Engineer

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Turlock, CA 95382
(209) 634-8105
FAX (209) 320-3526
chris_k@cornerstoneconsulting.biz

CORNERSTONE CONSULTING

Memo

To: Juan Villanueva

From: Chris Kiriakou

CC: Steve Escobar, Jeff Kaspar

Date: January 10, 2012

Re: CEC Regulations Regarding Renewable Portfolio Standard Cost Limitations (PUC §399.15 (c))

On April 19, 2012 the California Energy Commission conducted a webinar on their draft regulations for implementation of the 33 Percent Renewables Portfolio Standard (RPS). The session was conducted primarily by Angela Gould and Gabe Herrera of the CEC staff. There were approximately 15 publically owned utilities attending including SMUD and LADWP. Attached is the Agenda.

The discussion opened with the Public Utilities Code §399.15 (c) regarding cost limits. Following is the Code Section;

> §399.15 (c) The commission* shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. In establishing this limitation, the commission shall rely on the following:
>
> (1) The most recent renewable energy procurement plan.
>
> (2) Procurement expenditures that approximate the expected cost of building, owning, and operating eligible renewable energy resources.
>
> (3) The potential that some planned resource additions may be delayed or canceled.

*Although the Public Utilities Commission is stated (commission) §399.30 includes the POUs and refers to the Code section.

There was a considerable amount of discussion regarding the position of various utilities regarding rates, amount of rate increases, and price caps for renewables. It became clear that the Commission staff was looking for standards or "factors" that they could measure a utilities compliance with the regulations against. As an example, if a utility has a renewable project underway and it become delayed due to permitting or studies then the utility should have a list of alternate projects that they can fall back on to meet the 33% requirement in 2020 (recall Rough & Ready Solar).

Throughout the discussion the point was made that each POU's Board makes its own decisions with respect to projects, rates, timing, the plan to implement the 33% RPS requirement under the law, unproductive regulation, and whether or not the plan complies with the law. The CEC staff, at times, sounded frustrated.

For each of the eight agenda items the discussion focused on the amount of authority that would be removed from the POU's Board and relinquished to the CEC staff. PUC §399.30 specifies the code sections applicable to POUs which primarily involve 399.15 (c) and §399.16. It did not appear that the staff was able to resolve any of their compliance issues related to PUC §399.15 (c). Other PUC sections brought into the discussion included §399.15 (b) and (d);

> §399.15 (d) In developing the limitation pursuant to subdivision (c), the commission shall ensure all of the following:
>
> (1) The limitation is set at a level that **prevents disproportionate rate impacts** (emphasis added).
>
> (2) The costs of all procurement credited toward achieving the renewables portfolio standard are counted towards the limitation.
>
> (3) Procurement expenditures do not include any indirect expenses, including imbalance energy charges, sale of excess energy, decreased generation from existing resources, transmission upgrades, or the costs associated with relicensing any utility-owned hydroelectric facilities.

Section 399.15 (d) has a substantive provision in that it refers to ". . . disproportionate rate impacts." I used this to emphasize that small utilities that are surrounded by Investor Owned Utilities have a competitive rate issue with the IOU. I used the Port as only having commercial/industrial customers and being surrounded by PG&E had an especially competitive rate position. The City of Hercules was used as an example as having rates that are 25% higher than PG&E's and the utility is continuing to lose money.

The webinar lasted for a little over 2 Hours and did not conclude in any definitive standards to be included in the CEC proposed regulation. In summary, the group essentially replied to the CEC staff that implementation of the sections in question it's up to the individual Boards and Commissions and they may have multiple scenarios of implementation for individual utility circumstances. The schedule for moving the regulation towards implementation is as follows: In late May the draft CEC Regulation goes to the Office of Administrative Law (OAL) at which time a 45 day public comment period starts. At the conclusion of the comment period it then goes to the CEC Commission for approval. It is anticipated by staff that approval could take place in September.

Recommendation

The RPS is expressed in law and requires all California utilities to move toward supplying 33% of their retail sales with renewable energy in 2020 and thereafter. What is new with this legislation is that although the CEC will have no enforcement capability, they can refer it to the California Air Resources Board which does. PUC §399.30 requires that the Port's Commission:

1. insure that the utility implements procurement target periods specified in this article §399.30 (b),
2. insure that the utility procures the quantities specified in §399.30 (c) (1) and (2) (amounts, expenditures and impacts),
3. insure that the utility adopts procurement requirements consistent with the definition of Category 1, 2 and 3 renewable resources (§399.30 (c) (3)),
4. possibly adopt rules for procurement including excess procurement, delay and cost limitations (§399.30 (d) (1-3)
5. adopt a program for enforcement of this article (§399.30 (e)), and
6. post a notice when the utility adopts a procurement program in a public meeting with specified public notice to the CEC (§399.30 (f)).

It is recommended that the Port of Stockton develop a compliance plan that meets the requirements of the Public Utilities Code §399.30.

Agenda

Cost Limitations Webinar

April 19, 2012, 2:00 – 5:00 pm

https://energy.webex.com

Meeting number: 921 846 120

Meeting password: meeting@2

Call-in only: 1-866-469-3239 (enter meeting number when prompted)

1. Introductions
2. PUC Section 399.15 (c): do all provisions in this section apply to POUs?
3. Time period covered by cost limitation and frequency of revisions
4. Cost limitations after 2020
5. Definition of "all procurement credited toward achieving RPS" (Section 3206 (a)(3)(B)(2))
6. Definition of "delayed" and "canceled" (Section 3206 (a)(3)(C)(3))
7. Definition of "disproportionate" regarding rate impacts (Section 3206 (a)(3)(B)(1))
8. Direct vs. indirect costs
9. Sources of relied upon data for setting cost limitations

Renewable Portfolio Standard Procurement Plan

11/8/12

Agenda

- Background
- Regulatory
- Implementation
- Renewable Energy Requirements
- Recent Activities
- Strategic Implementation
- Proposed Procurement Strategy
- Impacts

Legislation

- In 2008 Governor Arnold Schwarzenegger signed Executive Order S-14-08.
- Requires electric utilities to achieve an electric generating portfolio that supplies electricity from 33% renewable resources by 2020.
- Governor Brown expanded it by signing SB X1-2.
- The California Energy Commission is preparing regulations to implement the plan.

Definitions

- Public Utilities Code Section 399.11 to 399.31 defines the program.

- Public Resources Code 25741(a) defines *Renewable Generation* as generating facilities that uses biomass, solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, digester gas, municipal solid waste conversion, landfill gas, ocean wave, ocean thermal, or tidal current, and any additions or enhancements to the facility using that technology.

Utility Implementation

- Investor Owned Utility programs are overseen by the Public Utilities Commission
- Publically Owned Utilities are overseen by the local Boards and the California Energy Commission
- The CEC is in the process of approving regulation applicable to POUs
- Public communication regarding renewable resource procurement.

CEC Regulation Requirements*

- Compliance be based on "qualifying electricity products"
- Renewable generating facilities must be certified by the CEC
- Performance requirements leading up to the 2020 requirement of 33% of retail sales supplied by renewable energy
- Three categories of electricity products

*Based on proposed July 2012 RPS Regulation

Renewable Resource Portfolio Content Categories

- PCC1 - Renewable Generation with bundled characteristics connected within or scheduled into California as is.

- PCC2 – Generation scheduled into CA but with intervening transmission, shaping and balancing services.

- PCC3 – Unbundled renewable energy credits purchased from facilities on the Western Grid.

Renewable Procurement Requirements*

Compliance Period	1/1/11 – 12/31/13	1/1/14 – 12/31/15	1/1/16 – 12/31/19	1/1/20 and beyond
Percent of Retail Sales	20%	20%	25%	33%
Portfolio Content Category 1	50%	65%	75%	>=75%
Portfolio Content Category 2				
Portfolio Content Category 3	25%	15%	10%	<=10%

* July 2012 Draft RPS Regulation

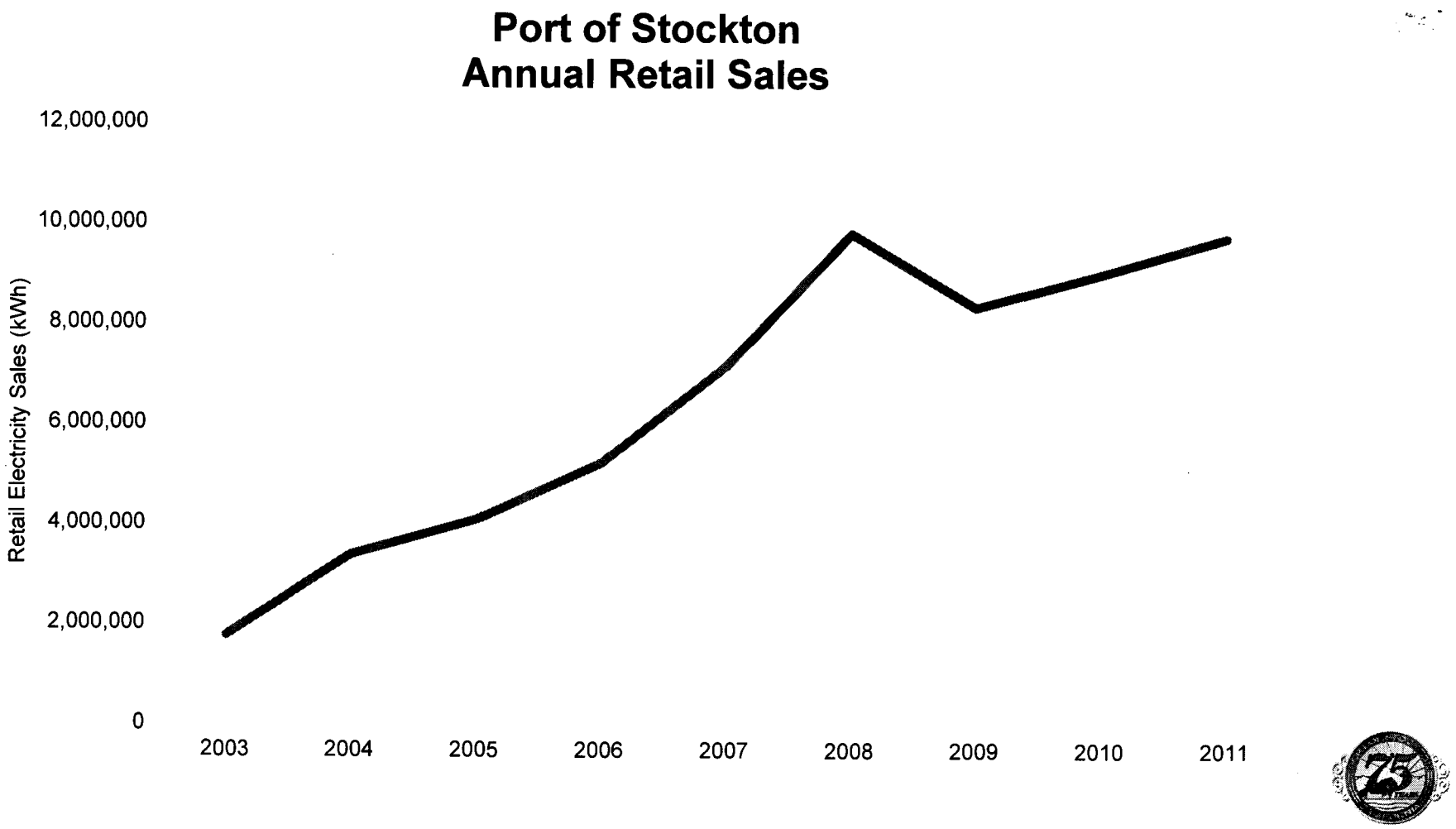
Investigations into Renewable Sources

- The Port staff has been investigating renewable energy sources since 2010.
- Worked with a developer to install 15 MW PV arrays on 30 of the Port's Warehouses.
- The final cost estimate was $0.14/kWh.

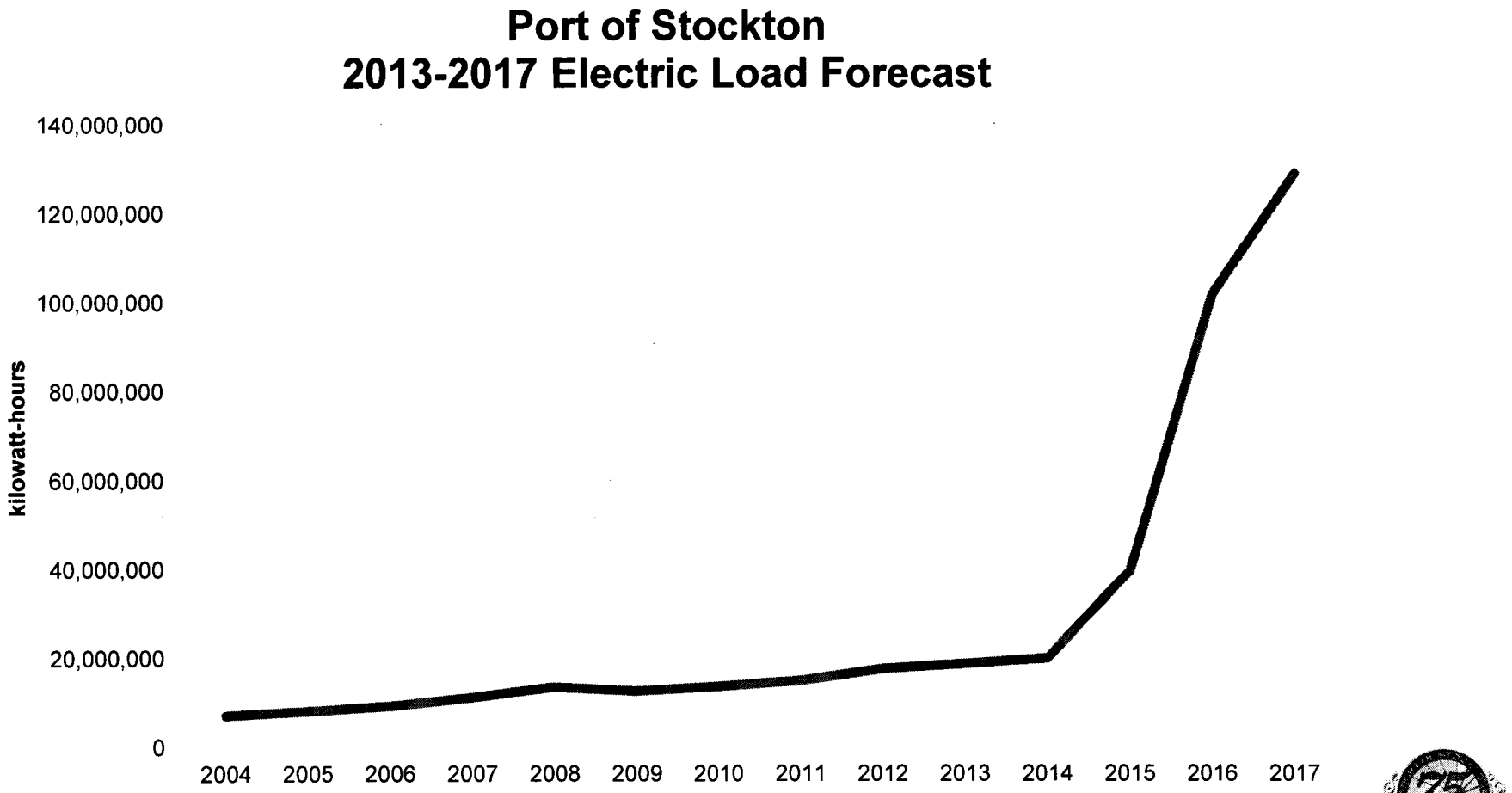
Timing and Financials

- During 2009 through early 2011 the Port was impacted by the economic turn down.
- Retail electric rates were near the adjacent investor owned utility.
- After mid-2011 the Port's cost structure improved due to a new power supply agreement.
- PV Panels have become more competitive.
- The Port's retail electric load has grown.

Retail Sale Growth



Load Forecast



Planning Horizon

- Two major tenants are contemplating sites on Rough & Ready Island.
- However, there is no firm commitment.
- Risk of committing to a resource in 2020 and not have the load
- The 2011 through 2014 load is fairly stable including a small amount of growth.
- Use 2013 -2014 as the planning horizon.

Port Criteria for Meeting the RPS

- Meet the RPS requirement
- Focus on 2013 and 2014 with an eye on 2015
- Use reliable technology
- Minimize operating cost impacts
- Use RECs (PCC 3) to the extent possible
- Locate on Port property if possible
- Size to not export power out of Port.
- Competitive procurement

RPS Procurement Plan

- 2013 –
  - Purchase 25% of the RPS requirement in the form of RECs.
  - Start the process to develop a 1,500 kW Solar photovoltaic generating facility to start commercial operation in 2014.
- 2014 –
  - Purchase 15% of the RPS requirement in the form of RECs.
  - 1,500 kW PV plant is in operation (2.5M kWh).

Proposed PV Power Plant

- Capacity sized to meet the RPS after purchase of RECs = 1,500 kW, 2.5M kWh
- Capital Cost Preliminary Estimate $1.6M
- Total annual cost debt service and O&M of $285,300.
- Anticipate bond financing (COPs)
- Commercial Operation date 2014.

Financial Impact
Operating Expenses

- Anticipated cost of RECs is currently very competitive.
- Proposed power plant cost per kWh is anticipated to be higher than current power supply contract.*
- Operational requirements on Port staff to be manageable within current operations.
- The 2014 retail rates will based on actual cost of service.

*Preliminary Estimates

Advantages

- Port of Stockton meets RPS requirements
- Resource stays local
- Manageable financial impact
- Load growth allows rates to remain competitive.
- Construction is local
- Port staff, with support, to manage project

QUESTIONS?

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chris_k@cornerstoneconsulting.biz

CORNERSTONE CONSULTING

Memo

To: Steve Escobar, Juan Villanueva

From: Chris Kiriakou

CC:

Date: January 31, 2014

Re: Options for Proceeding with Port of Stockton Solar Plant

The development of the 1.5 MW Port of Stockton Photovoltaic Plant is at a point where the construction format for the engineering, procurement and construction will need to be determined. There are four options for how the project can be further developed. The three elements of the development of the project are; 1) engineering including bid level design, construction and then as built drawings, 2) procurement including bid specification and approved equipment list, and 3) construction including the photovoltaic plant, possible energy storage and the 12 kV interconnection line to the substation. There are four options for handling the three elements as shown in the following table.

Construction Format Options	Engineering	Procurement	Plant Const.	12kV Const.
1. 100% Bid	Bid	Bid	Bid	Bid
2. Procurement & Construction Bid	HCS Engineering	Bid	Bid	Bid
3. Procurement & Construction less 12 kV	HCS Engineering	Bid	Bid	Bochmon & Woody
4. Procurement Only	HCS Engineering	Bid	Bochmon & Woody	Bochmon & Woody

To a varying extent HCS engineering should be involved in all construction options to insure compatibility with the Port's electric distribution system standards, system protection coordination with the Port's substation and PG&E, bid level engineering, construction oversight, as the Port's construction representative and an understanding of any operational constraints resulting from the existing system.

Option 1 – High level engineering for bidding and equipment specifications would be done by HCS but all other engineering, procurement and construction for the plant and the 12 kV interconnect line would be done by the low bidder.

Option 2 – HCS would perform the construction drawings and as built drawings as well as the bid level engineering. All other tasks would be done by the low bidder.

Option 3 – HCS would perform the same as Option 2 and Bochmon & Woody would construct the 12 kV distribution line to the substation under the existing O&M Agreement as a Special Project. The procurement of the equipment and the construction of the PV plant would be down by the lowest bidder.

Option 4 – Again HCS would perform the same as Option 2 and Bochmon and Woody would construct the plant and the 12 kV line. Equipment would be the only item out for bid.

The first option has all items out for bid and best insures lowest price. However, there is some loss of consistency with the Port's overall approach to system construction. Anytime a second engineer is engaged there will be some deviation from the design approach for the existing system. As we move down in options the project becomes more involved from a coordination point of view but utilizes the Port's existing contractors to a greater degree. Moving down in options does not necessarily insure lowest costs.

Recommendation

HCS Engineering has performed engineering for the Port's electric distribution system since its inception. HCS will need to be involved regardless of the bid format selected. They have provided a proposal to accomplish the all engineering and project management for $51,000. Because this is the Port's first generation project it will require a level of coordination between the existing system and the project that it has not experienced with the past substation project. For that reason as well as insuring that the project is consistent with the existing electric system it is recommended that Option 3 be utilized. This insures that a consistent engineering and distribution system construction approach using the existing HCS Engineer and O&M contractor. The PV Project procurement and construction tasks would be included in bid documents with project management oversight by HCS.

California Solar Statistics

View Solar Statistics
Find an Active Solar Contractor
Download Current CSI Data
Search for Applications
FAQs and Facts

Cost by System Size

This figure shows the average cost of completed systems in the CSI Program in relationship to their size. Gray dots indicate individual systems. Brown triangles indicate the average for a given system size range. Select the Table view below to display and download the average cost data represented by the brown triangles.

This report is current as of Feb. 5, 2014.

Cost vs. System Size

System Size (kW)	System Price ($/Watt)	# of samples
1.5	12.18	55
2.0	6.75	4
2.5	9.13	2
3.0	8.02	1
3.5	8.29	6
4.0	9.66	6
4.5	8.84	3
5.5	8.78	8
6.0	9.40	6
7.0	7.55	6
7.5	7.62	4
8.0	7.74	3
8.5	5.29	2
9.0	9.98	2
9.5	7.37	5
10.0	15.41	2
15.0	7.54	36
20.0	8.42	13
25.0	7.71	20
30.0	6.96	18
35.0	7.33	24
40.0	6.27	13
45.0	6.21	17
50.0	6.78	14
55.0	7.02	9
60.0	5.74	11
65.0	5.67	10
70.0	7.32	18
75.0	6.94	7
80.0	5.95	13
85.0	6.41	17
90.0	6.31	9
95.0	6.88	9

100.0	7.25	10
150.0	7.58	146
200.0	5.83	61
250.0	7.41	48
300.0	6.58	26
350.0	5.88	25
400.0	7.81	21
450.0	7.10	11
500.0	6.90	25
550.0	5.68	13
600.0	6.97	9
650.0	6.15	9
700.0	6.21	8
750.0	6.19	8
800.0	7.06	7
850.0	10.96	3
900.0	6.44	8
950.0	5.80	7
1000.0	2.58	2

820 application(s) were included for the generation of this chart.

Filters **Legend** ▲ Mean

Download filtered data

Display
- ○ Figure
- ◉ Table (xls)

Program
- ☑ General Market
- ☐ MASH
- ☐ SASH

Program Year [2]
- ◉ All Years
- ○ Range 2013 to 2014

Host Customer Sector
- ○ All Sectors
- ○ Residential
- ◉ Non-Residential
  - ☐ Commercial
  - ☐ Non-Profit
  - ☑ Government

Admin
- ○ All Admin
- ○ CCSE
- ◉ PG&E
- ○ SCE
- ○ GRID Alternatives

System Ownership [1]
- ◉ All
- ○ Host Customer
- ○ Third Party

System Size Source
- ○ CEC-AC
- ◉ DC (Nameplate)

Adjustments
- ◉ CPI Adjusted
- ○ Non-CPI Adjusted

This scatter plot is a random sample of all projects in the filtered data set.

[1] Costs for systems owned by third parties versus host customers ($/watt) cannot be directly compared. See the FAQ page for details.

[2] Program Year is set by the first of the following reservation dates: "Reserved Reservation", "Confirmed Reservation" or "Pending RFP". "Range" only includes projects that have an assigned Program Year. "All Years" also includes projects which have not yet been reserved.

Shell Energy North America (US), L.P.

The Stockton Port District	Shell Energy North America (US), L.P.
Contract ID:	Contract ID:
Deal Maker: Juan Villanueva	Deal Maker: Robert Pierce
Phone: 209.946.0246	Phone: (509) 951-1456
Fax: 209.464.7244	Fax: (858) 526-2140

TRANSACTION CONFIRMATION

Resource Contingent Bundled Renewable Energy ("PCC1") Resale

This Transaction Confirmation (this "Confirmation") is entered into this 26th day of September, 2014 ("Effective Date"), by and between **The Stockton Port District** ("Stockton Port District") and **Shell Energy North America (US), L.P.** ("Shell Energy"), each referred to herein individually as a "Party" and collectively as the "Parties", regarding the purchase and sale of the Product (as defined below) under the terms and conditions below. Additional definitions are included under the "Definitions / Interpretations" section below. The Master Agreement and this Confirmation shall be collectively referred to herein as the "Agreement."

Seller: Shell Energy

Buyer: Stockton Port District (WREGIS Account Holder Name "Stockton Port District")

Master Agreement: This Confirmation shall be governed by the Edison Electric Institute Master Power Purchase and Sale Agreement between the Parties dated October 13, 2010 (the "Master Agreement"). This Confirmation incorporates Schedule R of the WSPP Agreement dated effective March 4, 2014, which shall govern this Transaction except as modified in this Confirmation. References herein to sections in Schedule R shall appear, for example, as "Section R-2.3.4".

Product: **Portfolio Content Category 1 ("PCC 1")-Resource Contingent Bundled RECs:** Energy produced by the Project(s) (the "Project Energy") simultaneously bundled with the Renewable Energy Certificates ("RECs") that qualifies as a Resource Contingent Bundled REC as described in Section R-2.3.4. The Project Energy and RECs shall hereinafter be referred to collectively as the "Bundled Green Energy." The Product meets the RPS compliance requirements for Portfolio Content Category 1 as set forth in PUC Code 399.16(b)(1)(A) and CPUC Decision 11-12-052 as of the Effective Date of this Confirmation in a manner consistent with Section 3203(a) of the Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (CEC-300-2013-002-CMF), as adopted by the California Energy Commission effective October 1, 2013.

Environmental Attributes: Program Attributes as described under the "California Program" in the Definitions section hereof.

Project: As identified on Exhibit A. All Projects identified on Exhibit A are certified by the CEC as an ERR. Notwithstanding the foregoing, Seller may source the Product Contract Quantity from other Project(s) as identified on the attached Exhibit A, which may be updated from time to time at Seller's discretion. Seller shall notify Buyer in writing of any such updates to Exhibit A. Any of the Product delivered from a replacement Project(s) will comply with the California RPS as implemented in a manner consistent with the Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (CEC-300-2013-002-CMF), as adopted by the California Energy Commission effective October 1, 2013, and shall also be certified by the CEC as an ERR.

Contract Term: Commencing October 1, 2014 through the later of December 31, 2017, and continuing through the completion of the transfer of all RECs to Buyer through WREGIS and the payment of amounts due pursuant to this Confirmation.

Contract Quantity and Contract Price:

Year	Quantity	Price
2014	2,671	$19.00/MWh
2015	3,029	$19.00/MWh
2016	4,347	$19.00/MWh
2017	4,704	$25.00/MWh

Incremental Quantity: In addition to the Contract Quantity listed above, Buyer may request an Incremental Quantity of the Product as produced during calendar year 2015, 2016 or 2017. Buyer's request of such Incremental Quantity must occur no later than June 15th of each year, and must not exceed 10% of the Contract Quantity for each year. The table below lists the maximum amount of Incremental Quantity that Buyer may request for each year of the Contract Term.

Year	Maximum Incremental Quantity (MWh)
2015	303
2016	435
2017	470

Upon request of an Incremental Quantity from Buyer, Seller will confirm or deny the availability of the requested Incremental Quantity no later than June 30th.

If Seller confirms availability of the requested amount of Incremental Quantity Seller will supply and transfer the Incrementeal Quantity of the Product in accordance with the terms of this Confirmation, and Buyer will purchase the product at the Contract Price.

If Seller denies the availability of the Incremental Quantity, the parties may enter into a separate agreement for the sale and purchase of a separate quantity of the Product under mutually agreed to terms and conditions.

REC Transfer: Seller shall deliver the Product by transferring the RECs (through WREGIS), to Buyer's designated WREGIS account. Unless otherwise mutually agreed, Seller shall transfer RECs to Buyer as no later than June 1st of the year after they were produced.

Delivery Point: CAISO

Scheduling: Seller will perform all scheduling and tagging requirements as may be applicable to this transaction. These services will be performed consistent with all applicable CAISO and WECC Scheduling Protocols.

Settlements and Payment: Seller shall deliver the Product by transferring the RECs, with associated NERC e-Tags (if any) through WREGIS, to Buyer's designated WREGIS account. Buyer shall pay the applicable Contract Price no later than ten (10) days following receipt of Seller's invoice subsequent to the transfer of the RECs

Supporting Data: In the event that the Bundled Green Energy being transferred from Seller to Buyer originate from a Project(s) from outside of the state of California, Seller shall provide Buyer a reconciliation consisting of hourly meter data, tag data and associated calculations, lesser of each by hour, for each vintage month of PCC1 delivered to Buyer under this Confirmation.

Change in Law Provisions: Regulatorily Continuing (Section R-5.2.2(b)), requiring that Seller make commercially reasonable efforts to obtain compliance with Changes in Law in the designated Applicable Program, provided that such costs should not be greater than $1,000.00 (the "Capped Amount") including, without limitation, all matters relating to Special Provisions A(2) and A(4).

Compliance With RPS: (a) Seller's original contract meets the criteria of California Public Utilities Code Section 399.16(b)(1)(A) that the generation facility from which the electricity is procured is certified as eligible for the California renewables portfolio standard and either:

1. has its first point of interconnection to the Western Electricity Coordinating Council transmission grid within the metered boundaries of a California balancing authority area; or
2. has its first point of interconnection with the electricity distribution system used to serve end users within the metered boundaries of a California balancing authority area; or
3. the generation from that facility is scheduled into a California balancing authority without substituting energy from any other source, provided that, if another source provides real-time ancillary services required to maintain an hourly or subhourly import schedule into the California balancing authority only the fraction of the schedule actually generated by the generation facility from which the energy is procured may count toward this portfolio content category; or
4. the generation from that facility is scheduled into a California balancing authority pursuant to a dynamic transfer agreement between the balancing authority where the generation facility is located and the California balancing authority into which the generation is scheduled.

(b) The Confirmation herein is a resale and meets the following additional requirements:

1. The resale contract transfers only electricity and RECs that have not yet been generated prior to the effective date of this Confirmation;
2. The energy and associated RECs transferred by this Confirmation are transferred to Buyer, and the energy transferred by this Confirmation is transferred to Buyer in real time;
3. If applicable, the RPS-eligible energy is scheduled from eligible renewable energy resource(s) that is not interconnected to a California balancing authority into a California balancing authority without substituting energy from another source, and the original hourly or subhourly schedule is maintained.

SPECIAL PROVISIONS:

A. Non-Modifiable Standard Terms and Conditions

(1) **"Green Attributes"** means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to RECs, as well as: (1) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx),

nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere;[1] (3) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Buyer to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Buyer's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. Green Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project. **[STC 2, RECs and Green Attributes, Non-Modifiable.]**

Green Attributes: Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project. **[STC 2 - RECs and Green Attributes, Non-Modifiable. D.08-04-009 (3.2)]**

(2) Eligibility: Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. **[STC 6, Non-Modifiable. (Source: D.07-11-025, Attachment A.) D.08-04-009]**

(3) Applicable Law. Governing Law. This Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each Party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Agreement. **[STC 17, Applicable Law, Non-Modifiable. (Source: D.07-11-025, Attachment A) D.08-04-009].**

(4) Transfer of Renewable Energy Credits: Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the renewable energy credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. **[STC REC-1, Non-modifiable. D.11-01-025]**

(5) Tracking of REC's in WREGIS: Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract. **[STC REC-2, Non-modifiable. D.11-01-025]**

B. Additional Terms and Conditions

(1) Seller Representations and Warranties: Seller represents and warrants:

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

(a) Seller has not sold the Product or any Green Attributes of the Product to be transferred to Buyer to any other person or entity;

(b) each Green Attribute meets the specifications set forth herein;

(c) the Product is from the electric energy generated by the Project(s);

(d) All rights, title and interest in and to the Product are free and clear of any taxes or security interests except for any right or interest by any entity claiming through Buyer;

(e) Seller receives compensation directly from the California ISO for energy imported in real-time on Buyer's behalf.

(2) Buyer Representations and Warranties. Buyer represents and warrants that Buyer has taken all necessary steps to establish a WREGIS account to facilitate the RECs to be transferred from Seller to Buyer prior to the first delivery under this Confirmation.

(3) Review: To monitor compliance with this Confirmation, each Party reserves the right to review during normal business hours and at its own expense, for up to two (2) years following delivery of the Bundled Green Energy under this Confirmation, and with reasonable advance notice to the other Party and to the extent that such other Party is in possession of such information information required to verify that the Green Attributes sold under this Confirmation were not otherwise sold by Seller to a third party.

(4) Regulatory: The Parties intend the rates, terms and conditions of service specified in this Confirmation to remain fixed throughout the Term of this Confirmation regardless of any changes in underlying costs that would justify a change in rates under traditional cost of service principles. Neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Confirmation, notwithstanding any subsequent changes in Applicable Law, its costs of service or market conditions that may occur.

(5) Forward Contract: This Confirmation constitutes a sale of a nonfinancial commodity for deferred shipment or delivery that the parties intend to be physically settled and is excluded from the term "swap" as defined in the Commodity Exchange Act under 7 U.S.C. § 1a(47) and Commodity Future Trading Commission and Securities and Exchange Commission regulations under Title 17 of the Code of Federal Regulations Part 1 and Title 17 of the Code of Federal Regulations Parts 230, 240, and 241, respectively.

(6) Mutual Representations and Warranties. During the Term, each Party represents and warrants to the other that: (i) it is an "eligible commercial entity" and an "eligible contract participant" within the meaning of United States Commodity Exchange Act §§1a(11) and 1a(12), respectively, and this Transaction has been subject to individual negotiation by the Parties.

AMENDMENTS TO THE MASTER AGREEMENT

Governing Law. For purposes of this Confirmation only, Section 10.6, Governing Law, of the Master Agreement is deleted in its entirety and replaced with the Section A(3) Applicable Law provision under "SPECIAL PROVISIONS" herein.

Confidentiality. Section 10.11, Confidentiality, of the Master Agreement is amended for purposes of this Confirmation by inserting at Line 7 after the word "proceeding" prior to the semicolon the following: "or to Deliver RECs pursuant to the requirements of WREGIS".

DEFINITIONS / INTERPRETATIONS: For purposes of this Confirmation, the following definitions and rules of interpretations shall apply:

"Applicable Law" means all legally binding constitutions, treaties, statutes, laws, ordinances, rules, regulations, orders, interpretations, permits, judgments, decrees, injunctions, writs and orders of any Governmental Authority or arbitrator that apply to the Applicable Program or any one or both of the Parties or the terms hereof.

"Applicable Program" the definition of Applicable Program in Schedule R shall mean the California Renewable Portfolio Standard as defined herein.

"CAISO" means the California Independent System Operator, or its successor.

"California Program", "California Renewables Portfolio Standard" or "California RPS" means the renewable energy program and policies, codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time and as implemented in a manner consistent with the Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (CEC-300-2013-002-CMF), as adopted by the California Energy Commission effective October 1, 2013.

"CEC" means the California Energy Commission or its regulatory successor.

"CEC Certification" means, if applicable, the certification by the Certification Authority of the California RPS program of (i) the creation and characteristics of a REC, (ii) the qualification of a Renewable Energy Facility or a Renewable Energy Source under the California RPS program, (iii) Delivery of a REC or (iv) other compliance with the requirements of the California RPS program.

"CPUC" means the California Public Utilities Commission or its regulatory successor.

"ERR" means Eligible Renewable Resource as that term is defined by the CEC.

"FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

"Governmental Authority" means any international, national, federal, provincial, state, municipal, county, regional or local government, administrative, judicial or regulatory entity operating under any Applicable Laws and includes any department, commission, bureau, board, administrative agency or regulatory body of any government.

"HE" means the hour ending.

"Off-Peak (LLH)" means all hours other than On-Peak hours.

"On-Peak (HLH)" means 6x16 (Monday through Saturday, HE 0700 – HE 2200 PPT, excluding NERC holidays).

"Project" has the meaning set forth on the first page hereof.

"Project Energy" means the hourly Energy produced by the Project.

"PPT" means Pacific prevailing time.

"STC" stands for Standard Terms and Conditions of the CPUC relating to purchase and sales of Green Attributes.

"WECC" means the Western Electricity Coordinating Council or its successor organizations.

"WREGIS" means the Western Renewable Energy Generation Information System or its successor systems.

"WREGIS Certificates" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

"WREGIS Operating Rules" means those operating rules and requirements adopted by WREGIS as of July 15, 2013, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

Notwithstanding anything contained in the Master Agreement to the contrary, this Confirmation shall only be effective when executed by both Parties. Please sign and return by facsimile to Shell Energy at (858) 526-2140 and (713) 767-5414.

IN WITNESS WHEREOF, the Parties have signed this Confirmation effective as of the Effective Date.

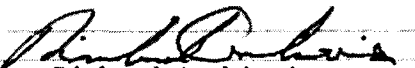
The Stockton Port District	**Shell Energy North America (US), L.P.**
By: 	By:
Name: Richard Aschieris	Name:
Title: Port Director	Title:

Exhibit A
Project(s)

RPS ID	Facility Name	WREGIS ID	County	State	Eligibility Date	On-line Date
60736A	Cabazon Wind	W834	Riverside	CA	11/19/2008	10/1/2002
60737A	Whitewater Hill Wind	W835	Riverside	CA	11/19/2008	11/1/2002
62288A	Palouse Wind	W2906	Whitman	WA	12/14/2012	12/24/12
60721A	White Creek Wind	W360	Roosevelt	WA	8/24/2007	2/28/2008
60495A	Kettle Falls Woodwaste Plant	W130	Stevens	WA	1/1/1983	8/9/2012

Shell Energy North America (US), L.P.

The Stockton Port District	Shell Energy North America (US), L.P.
Contract ID:	Contract ID:
Deal Maker: Juan Villanueva	Deal Maker: Robert Pierce
Phone: 209.946.0246	Phone: 509.951.1456
Fax: 209.464.7244	Fax: (858) 526-2140

CONFIRMATION AGREEMENT
RECs Only – Portfolio Content Category 3 ("PCC3")

This Confirmation Agreement (this "Confirmation") is entered into this 26th day of September, 2014 ("Effective Date"), by **The Stockton Port District** ("Stockton") and **Shell Energy North America (US), L.P.** ("Shell Energy"), each referred to herein individually as a "Party" and collectively as the "Parties", regarding the purchase and sale of the Product (as defined below) under the terms and conditions set forth herein. Additional definitions are included under the "Definitions/Interpretations" section below. The Master Agreement and this Confirmation shall be collectively referred to herein as the "Agreement."

Seller: Shell Energy

Buyer: Stockton (WREGIS Account Holder Name "Stockton Port District"))

Master Agreement: This Confirmation shall be governed by the Edison Electric Institute Master Power Purchase and Sale Agreement between the Parties dated October 13, 2010 (the "Master Agreement"). This Confirmation incorporates Schedule R of the WSPP Agreement dated effective March 4, 2014, which shall govern this Transaction except as modified in this Confirmation. References herein to sections in Schedule R shall appear, for example, as "Section R-2.3.3".

Product: **Portfolio Content Category 3 ("PCC 3")-Resource Contingent RECs.** Compliance Period 2 RECs and Compliance Period 3 RECs that comply with the California Code Pub. Util. Code §399.16(b)(3) and as further defined in CPUC D.11-12-052 (Decision Implementing RPS Portfolio Content Categories). To the extent not inconsistent with the foregoing sentence, each REC shall, be a "Resource Contingent REC" as defined in Section R-2.3.3. The Product meets the RPS compliance requirements for Portfolio Content Category 3 as set forth in PUC Code 399.16(b)(3) and CPUC Decision 11-12-052 as of the Effective Date of this Confirmation in a manner consistent with Section 3203(a) of the Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (CEC-300-2013-002-CMF), as adopted by the California Energy Commission effective October 1, 2013.

Environmental Attributes: Program Attributes as described under the "California Program" in the Definitions section hereof.

Projects: Seller may source the Product to meet the Contract Quantity from any Project(s) that complies with the CPUC Regulations for that Product as defined above, and is certified by the CEC as an ERR. Any of the Product delivered from a replacement Project(s) will comply with the California RPS as implemented in a manner consistent with the

Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (CEC-300-2013-002-CMF), as adopted by the California Energy Commission effective October 1, 2013, and shall also be certified by the CEC as an ERR.

Delivery Period : Commencing October 1, 2014, through December 31, 2017, and continuing through the completion of the transfer of all RECs to Buyer through WREGIS and the payment of amounts due pursuant to this Confirmation.

Contract Quantity and Contract Price:

Year	Quantity	Price
2014	85	$2.25/REC
2015	534	$2.25/REC
2016	483	$2.25/REC
2017	523	$3.00/REC

Incremental Quantity: In addition to the Contract Quantity listed above, Buyer may request an Incremental Quantity of the Product as produced during calendar year 2014, 2015, 2016 or 2017. Buyer's request of such Incremental Quantity must occur no later than September 15th of each year, and must not exceed 10% of the Contract Quantity for each year. The table below lists the maximum amount of Incremental Quantity that Buyer may request for each year of the Contract Term.

Year	Maximum Incremental Quantity (REC)
2014	9
2015	53
2016	48
2017	52

Upon request of an Incremental Quantity from Buyer, Seller will confirm or deny the availability of the requested Incremental Quantity no later than September 30th of the applicable year.

If Seller confirms availability of the requested amount of Incremental Quantity Seller will supply and transfer the Incremental Quantity of the Product in accordance with the terms of this Confirmation, and Buyer will purchase the product at the Contract Price.

If Seller denies the availability of the Incremental Quantity, the parties may enter into a separate agreement for the sale and purchase of a separate quantity of the Product under mutually agreed to terms and conditions.

Transfer and Payment: Seller shall deliver the Product by transferring the RECs (through WREGIS), to Buyer's designated WREGIS account. Buyer shall pay the applicable Contract Price no later than ten (10) days following receipt of Seller's invoice subsequent to the transfer of the RECs.

Change in Law: Regulatorily Continuing (Section R-5.2.2(b)), requiring that Seller make commercially reasonable efforts to obtain compliance with Changes in Law in the designated Applicable Program, provided that such costs should not be greater than $1,000.00 (the "Capped Amount") including, without limitation, all matters relating to Special Provisions A(2) and A(4).

SPECIAL PROVISIONS:

A. Non-Modifiable Standard Terms and Conditions

(1) **"Green Attributes"** means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to RECs, as well as: (1) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere;[1] (3) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Buyer to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Buyer's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. Green Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project. **[STC 2, RECs and Green Attributes, Non-Modifiable.]**

Green Attributes: Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project. **[STC 2 - RECs and Green Attributes, Non-Modifiable. D.08-04-009 (3.2)]**

(2) Eligibility: Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

commercially reasonable efforts to comply with such change in law. **[STC 6, Non-Modifiable. (Source: D.07-11-025, Attachment A.) D.08-04-009]**

(3) Applicable Law. Governing Law. This Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each Party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Agreement. **[STC 17, Applicable Law, Non-Modifiable. (Source: D.07-11-025, Attachment A) D.08-04-009].**

(4) Transfer of Renewable Energy Credits: Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the renewable energy credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. **[STC REC-1, Non-modifiable. D.11-01-025]**

(5) Tracking of REC's in WREGIS: Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract. **[STC REC-2, Non-modifiable. D.11-01-025]**

B. Additional Terms and Conditions

(1) Seller Representations and Warranties: Seller represents and warrants:

(a) Seller has not sold the Product or any Green Attributes of the Product to be transferred to Buyer to any other person or entity;

(b) each Green Attribute meets the specifications set forth herein;

(c) the Product is from the electric energy generated by the Project;

(d) All rights, title and interest in and to the Product are free and clear of any taxes or security interests except for any right or interest by any entity claiming through Buyer;

(2) Buyer Representations and Warranties. Buyer represents and warrants that Buyer has taken all necessary steps to establish a WREGIS account to facilitate the RECs to be transferred from Seller to Buyer prior to the first delivery under this Confirmation.

(3) Review: To monitor compliance with this Confirmation, each Party reserves the right to review during normal business hours and at its own expense, for up to two (2) years following delivery of the RECs under this Confirmation, and with reasonable advance notice to the other Party and to the extent that such other Party is in possession of such information required to verify that the Green Attributes sold under this Confirmation were not otherwise sold by Seller to a third party.

(4) Regulatory: The Parties intend the rates, terms and conditions of service specified in this Confirmation to remain fixed throughout the Term of this Confirmation regardless of any changes in underlying costs that would justify a change in rates under traditional cost of service principles. Neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Confirmation, notwithstanding any subsequent changes in Applicable Law, its costs of service or market conditions that may occur.

(5) Forward Contract: This Confirmation constitutes a sale of a nonfinancial commodity for deferred shipment or delivery that the parties intend to be physically settled and is excluded from the term "swap" as defined in the Commodity Exchange Act under 7 U.S.C. § 1a(47) and Commodity Future Trading Commission and Securities and Exchange Commission regulations under Title 17 of the Code of Federal Regulations Part 1 and Title 17 of the Code of Federal Regulations Parts 230, 240, and 241, respectively.

(6) Mutual Representations and Warranties. During the Term, each Party represents and warrants to the other that: (i) it is an "eligible commercial entity" and an "eligible contract participant" within the meaning of United States Commodity Exchange Act §§1a(11) and 1a(12), respectively, and this Transaction has been subject to individual negotiation by the Parties.

AMENDMENTS TO THE MASTER AGREEMENT

Governing Law. For purposes of this Confirmation only, Section 10.6, Governing Law, of the Master Agreement is deleted in its entirety and replaced with the Section A(3) Applicable Law provision under "SPECIAL PROVISIONS" herein.

Confidentiality. Section 10.11, Confidentiality, of the Master Agreement is amended for purposes of this Confirmation by inserting at Line 7 after the word "proceeding" prior to the semicolon the following: "or to Deliver RECs pursuant to the requirements of WREGIS."

DEFINITIONS / INTERPRETATIONS: For purposes of this Confirmation, the following definitions and rules of interpretations shall apply:

"Applicable Law" means all legally binding constitutions, treaties, statutes, laws, ordinances, rules, regulations, orders, interpretations, permits, judgments, decrees, injunctions, writs and orders of any Governmental Authority or arbitrator that apply to the Applicable Program or any one or both of the Parties or the terms hereof.

"Applicable Program" the definition of Applicable Program in Schedule R shall mean the California Renewable Portfolio Standard as defined herein.

"California Program", "California Renewables Portfolio Standard" or "California RPS" means the renewable energy program and policies, codified in California Public Utilities Code Sections 399.11 through 399.32 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time and as implemented in a manner consistent with the Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities (CEC 300 2013 002 CMF), as adopted by the California Energy Commission effective October 1, 2013,

"CEC" means the California Energy Commission or its regulatory successor.

"CPUC" means the California Public Utilities Commission or its regulatory successor.

"ERR" means Eligible Renewable Resource as that term is defined by the CEC.

"FERC" means the Federal Energy Regulatory Commission or its regulatory successor.

"Governmental Authority" means any international, national, federal, provincial, state, municipal, county, regional or local government, administrative, judicial or regulatory entity operating under any Applicable Laws and includes any department, commission, bureau, board, administrative agency or regulatory body of any government.

"STC" stands for Standard Terms and Conditions of the CPUC relating to purchase and sales of Green Attributes.

"WECC" means the Western Electricity Coordinating Council or its successor organizations.

"WREGIS" means the Western Renewable Energy Generation Information System or its successor systems.

"WREGIS Certificates" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

"WREGIS Operating Rules" means those operating rules and requirements adopted by WREGIS as of July 15, 2013, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

Notwithstanding anything contained in the Master Agreement to the contrary, this Confirmation shall only be effective when executed by both parties. Please confirm that the terms and conditions stated herein accurately reflect the agreement reached by Buyer and Seller by signing and returning by facsimile to Shell Energy at (858) 526-2140 and (713) 767-5414.

IN WITNESS WHEREOF, the Parties have signed this Confirmation effective as of the Effective Date.

The Stockton Port District	**Shell Energy North America (US), L.P.**
By:	By:
Name: Richard Aschieris	Name:
Title: Port Director	Title:

	Pasadena	Anaheim
1. staff #	372	355
2. staff hours	1519 hours	27 employees
3. new staff?	Due to budget constraints and ongoing rate impact concerns, existing staff are being reassigned and their efforts redirected from other activities as neeed to support implementation of the RPS regulations	Aneheim does not plan to hire additional staff for RPS compliance. One staff member is currently assigned to RPS compliance, and is responsible for all aspects of RPS compliance. A total of 11 staff members have assisted with RPS compliance
4. Cost of procurement plan	Reliable cost data beyond 2013 is proprietary and not available	Anaheim prepares the procurement and enforcement plans together; see #5
5. cost of procurement plan implementation	Reliable cost data beyond 2013 is proprietary and not available	RPS compliance takes up 15% of one full time staff member's time, at a cost of $15,600 per year. In addition, a total of 11 other staff members have worked on SBX 1 2, including legislative staff, settlements staff, and resource planning staff, at a total POU cost of $50,000.

	Pasadena	Anaheim
6. Certification	It is anticipated that third party auditing costs wil equal $10,000 to $15,000 per year	Anaheim has spent approximately 40 hours of staff time researching repowering, at an estimated cost of $2000. The cost for any additional compliance requirements are embedded in our annual cost projections
7. WREGIS	It is anticipated that WREGIS costs will be about $2000 to $3000 per year	Approximately $10,000 is spent on these two items (and is included in the total annual cost)
8. Additional costs	Additional resource procurement costs will lead to higher electric rates. Because we intend to perform th compliance efforts with existing staff resources, additional direct costs may be limited to overtime and contract costs for consulting and legal support as needed. It is likely that we will incur opportunity costs, such as non-optimal procurement or less efficient operations as a result of shifting staff resources to compliance activities	Costs associated with the negotiation and contractual obligations of RPS contracts that may not count as part of RPS compliance or fall within the PRCCs for which it is contracted can cost a utility tens of millions of dollars. Additionally, investment in DG and rooftop solar is highly discounted; it is projected that Anaheim will spend over $10 million on DG.

	Pasadena	Anaheim
9. New business?	No, procurement requirements will be assigned to appropriate staff within the existing organization	The requirements of SBX1 2 make doing business in CA costly. There is a potential for more local renewable resource development, if the CEC and Air Quality Districts can work together for cost efficient resource development.
Third party verification	It is anticipated that third party auditing costs wil equal $10,000 to $15,000 per year	If third party verification of data is required, it will cost an additional $10,000 per year, with the total RPS compliance cost exceeding $60,000

	Glendale	Burbank
1. staff #	419, approx $34.87 million	293
2. staff hours	33246 hours	very small
3. new staff?	As a direct result of the RPS program, GWP has increased 6 people to its staffing levels and added over $760,000 to th annual budget starting in 2010. Also, additional consultants are being hired to review renewable contracts and evaluate options. Both internal and external legal counsel are relied upon.	No plans exist at this time and we hope to avoid the need for additional staff; however, given the complexity in complying with the multiple regulatory matters we expect there may be one or two additional staff resquired. The area where we have seen the most significant increases in staffing is in the need for outside consultants and legal consultants.
4. Cost of procurement plan	GWP's comprehensive procurement plan has not yet been adopted. GWP expects to spend at least 100 staff hours on the devleopment of the procurement plan in 2012, including legal, management, and other staff. There will be additioanl costs for consultants to make sure that our long-term portfolio evaluation model will be capable of handing new requirements.	A procurement plan has been developed. We expect to change, modify, or update this plan as additional resources are identified and approval is sought from Council to enter into contracts. At a minimum, the current plan results in an approximate 1% rate increase for 1% increase in renewable energy. We seek to reduce that effect as much as possible.
5. cost of procurement plan implementation	Unknown at this time. Negotiations are underway with several developers. In addition, this question does nto specify the economic accounting perspective. GWP plans to use th ratepayer perspective: how much will retail rates increase because of the implementation of a procurement plan.	Burbank is a fully resourced utility and the implentation of the mandated RPS program adds to the complexity and challenge of our current situation. Consequently, adding renewable energy means that we've added resources that are not needed to serve our retail customers. Determining the cost of these extra resources has not been calculated nor is it clear how such costs might be calculated.

	Glendale	Burbank
6. Certification	Not enough information is available regarding the types of renewable resources we will be able to use to answer this question fully. Considerable costs have already been expended fo legal and staff time regarding the uncertainty of biomethane issues. GWP does expect to spend additional amounts on outside consultants for facility-specific issues such as separating RECs produced by multiple phases of expansion of a given renewable facility. Both legal and engineering services may be required.	Such costs are hard to quantify but it is estimated that each pre-certification and certification application could take about 1 day to process. Of course dealing with follow-up questions and inquiries from the CEC would take additional time.
7. WREGIS	Estimated $65,000 (20%) to $67,200 (33%) in annual fees paid directly to WREGIS. This does nto include staff time associated with such participation, nor does it include costs for verification.	It is estimated that the annual fes paid directly to WREGIS will range from $75,000 to $100,000 annually. In addition, having to pay for third party verification as well as staff time would likely have a similar cost. The total cost would be expected to be between $125,000 and $175,000 per year
8. Additional costs	GWP plans to use a ratepayer perspective: how much higher will ratepayer costs be due to a specific procurement plan. These costs will include all incremental costs and lost revenues, both of which will cause retail rates to increase. Other costs may come from implementing smart grid meters, demand response, energy storage, transmission issues, repowering, GHG obligations, EPA requirements	The potential cost of having to follow-up with the CEC on questions they might have related to verification and certification, and reporting would take staff time and effort. Potentially responding to third-party requests or "special" investigations by the CEC would also cost staff time. Also, there might be a need to hire more outside legal help to answer questions, prepare regulatory filings, and represent us before the CEC, for ongoing regulatory compliance

	Glendale	Burbank
9. New business?	Potentially more regulatory staff needed, and possible expansion in energy storage companies and service to integrate variable renewable resource.	Yes- jobs will be created to build new facilities as well as to operate and maintain them wherever they are located. Along with the increase in jobs for building new renewables, there is also the need to respond to regulatory agencies which requires more staff time and potential outside consultants and legal resources.
Third party verification		Third party verification could cost $50,000-$75,000 a year.

	LADWP	Imperial Irrigation
1. staff #	9185	538
2. staff hours	15649 hours	18 employees
3. new staff?	Yes, the LADWP plans to hire additional staff	yes
4. Cost of procurement plan	The total estimated cost of adoption of a renewable energy procurement plan is $2,122,449. The total estimated cost of adoption of an enforcement plan is $2,523,678	Staff and consultant time and costs spent over th past 12 months to understand, draft and adopt various regulations and rules and to negotiate contracts to comply with the RPS procurement and enforcement plans required by SB 1x 2 has been approximately $246, 075. In any given compliance period, the administrative costs of enforcement will include staff time necessary to draft he reports to the IID Board of Directors and the Commission establishing compliance.
5. cost of procurement plan implementation	Annual mplementation cost is estimated to be $6,873,557	For example, in March 2012 IID spent approximately $7000 for staff and consultants' time and expenses to track, attend, and participate in the CEC proceedings reviewing eligible renewable resource types and other RPS issues.

	LADWP	Imperial Irrigation
6. Certification	Compared to current opreations, LADWP estimates a cost of $589,700 for applying and maintaining RPS certification	At this time, IID estimates that it will have to hire two new employees to assist in applying for and maintaining RPS certifications. The cost of two employees' salary and benefit packages would total $120,000-$160,000 depending on the experience and education required for the positions.
7. WREGIS	LADWP estimates a total cost of $4,269,600	IID estimates that participation in the generation tracking and verification system will cost an additioanl $3000 to $5000 per year, plus the costs of the two full-time employees for certification
8. Additional costs	LADWP has taken into consideration additional estimated cost of $2,237,600	IID is a transmission operator and certified balancing authority within the WECC. As IID interconnects more renewable energy to its BA, it will be faced with increasing costs of balance and regulate this intermittent generation.

	LADWP	Imperial Irrigation
9. New business?	Yes, there is potential for th creation of new businesses as ar esult of an increase in procurement requirements under the RPS. The CEC needs to take into consideration that disqualification of certain eligible renewable energy resources (biomethane) can be detrimental to existing and dependable businesses.	IID is uniquely situated in a region of the state with significant renewable resources. IID has been a strong proponent of the development of renewable energy projects in the Imperial Valley as a means to spur economic development and create new green jobs. IID has supported the development of renewable energy by undertaking a transmission build-out that will facilitate the export of renewable energy to other parts of CA. The development of Imperial Valley's renewable potential has the potential to create new businesses and new jobs in a region of the State that has long suffered from chronic high unemployment and high povery rates.
Third party verification		

	SMUD	Port of Stockton
1. staff #	1850	94
2. staff hours		
3. new staff?	SMUD already has staff working on RPS, and expects to hire one or two students to help prepare certifications, enter data in WREGIS, and prepare reports	The Port most likely will rely on consultants, outside contractors and developers to assist it in meeting the State's RPS requirements.
4. Cost of procurement plan	SMUD estimates that the incremental cost above previous level of staff time is no more than $100,000 in staff time	The Port is currently developing a formal RPS development plan consistent with the draft RPS Regs. Between staff time and consultants it is estimated that the plan will require approximately $25,000.
5. cost of procurement plan implementation	SMUD already has staff working on RPS, and does not believe there is any incremental cost above previous level of effort.	Cost of implementation will be dependent upon the final RPS Regulations. However, based on previous project development work we anticipate that at least $100,000 in project studies involving PG&E and the CAISO will be required as well as significant staff time.

	SMUD	**Port of Stockton**
6. Certification	No incremental administrative cost above previous level of effort	Its not clear at this time what the Certification costs will be.
7. WREGIS	No incremental administrative cost above previous level of effort	WREGIS fees will be dependent upon the RECs versus generating project decision for the Port.
8. Additional costs	If RPS regulations do not allow counting of historical procurement, cost of $100 million dollars to SMUD ratepayers. Second, cost to SMUD ratepayers if behind the meter generation is not PCC 1. Third, additional costs for reporting to the CEC between $10,000-$100,000 annually. CEC should minimize reporting burden. Fourth, additional costs from ARB penalties - CEC should allow POU governing board to enforce first.	The incremental cost of renewable generation will be dependant upon the Port's final strategy for implementation. However, we believe that it could range between $40,000 and $200,000 depending on strategy and Regulations. This amounts to an estimated additional 8.25% revenue requirement for new renewable generation. The Port's load is 100% commercial/industrial and this rate pressure will place competitive pressure on the Port from the surrounding IOU.

	SMUD	**Port of Stockton**
9. New business?	Could lead to the creation of new businesses for tracking and verifying renewable procurement meets category requirements	The RPS regulations could lead to new jobs within the region but only for the construction period of the projects, if built.
Third party verification		

The Stockton Port District	Shell Energy North America (US), L.P.
Contract ID:	Contract ID:
Deal Maker: Juan Villanueva	Deal Maker: Robert Pierce
Phone: 209-946-0246	Phone: 509-688-6063
Fax : 209-464-7244	Fax: 858-320-2674

CONFIRMATION AGREEMENT
Green Attributes (RECs Only – Bucket 3) – WSPP Agreement

This Confirmation Agreement ("Confirmation" or "Agreement") is entered into December 21, 2012 ("Effective Date") by and between **The Stockton Port District** ("Stockton" or "Buyer") and **Shell Energy North America (US), L.P.** ("Shell Energy" or "Seller"); each individually a "Party" and collectively the "Parties", regarding the purchase and sale of products under the terms and conditions below.

Master Agreement:	EEI Master Power Purchase and Sale Agreement between the Parties dated October 13, 2010 (the "EEI Master Agreement").
Transaction:	Buyer is buying Renewable Energy Credits ("RECs") from Seller and Buyer shall take title to such during the Delivery Term herein.
Project:	The RECs sold by Seller to Buyer are produced by Phase III of the Nine Canyon Wind Project that: (i) is certified with the CEC and qualifies as an Eligible Renewable Resource, as such term is defined in Public Utilities Code Section 399.12 or Section 399.16, (CEC number 60803A), (ii) is located near Finley, Washington, (iii) is a 32.2 MW phase of a the larger Nine Canyon wind facility, and (iv) (a) Phase III commenced commercial operation after January 1, 2005, and (b) is interconnected to the BPA transmission system (the "Project").
Product:	Green Attributes sourced by the Project, as such Product is described in the Code Pub. Util. Code §399.16(b)(3) and as further defined in CPUC D.11-12-052 (Decision Implementing RPS Portfolio Content Categories).
Seller:	Shell Energy
Buyer:	Stockton
Delivery Term:	The Delivery Term of this Transaction shall commence upon the Effective Date and shall continue through December 31, 2014, and until the Parties have fulfilled all obligations with respect to the Transaction, including the transfer of all RECs via WREGIS Certificates to Buyer and the payment of amounts due pursuant to this Confirmation.
Vintage:	Calendar year 2014.
Contract Quantity:	388 RECs
RECs Contract Price:	$1.75 per REC.
Delivery Point:	Title to RECs shall transfer from Seller to Buyer through WREGIS.
Transfer Date:	On or before December 31, 2014.

Change in Law: If any action by the CPUC or any state, federal or local Governmental Authority or agency occurs after the Effective Date hereof and the result of such action is that Buyer is precluded from using the Product purchased herein to satisfy the California Renewables Portfolio Standard requirement ("Change in Law") Buyer may elect to terminate this Confirmation by delivering to the other Party written notice of such termination not later than 60 days following the effective date of the Change in Law. In the event Buyer does not exercise its right to terminate this Confirmation due to a Change in Law within such 60 day period, Buyer may not thereafter terminate this Confirmation due to the Change in Law. A termination of this Confirmation due to a Change in Law shall be effective upon the delivery of written notice therefore and thereafter:

(i) all obligations to Deliver RECs not then already transferred by Seller to Buyer shall be terminated and Seller shall have no obligation to make any further deliveries, and Buyer shall have no obligation to accept any transfer, of Green Attributes;

(ii) If Buyer refuses to accept Delivery of the RECs due to the Change in Law, neither Party shall be liable for damages;

(iii) neither Party shall have any further obligations to the other hereunder with respect to RECs not Delivered due to a proper termination in accordance with the foregoing.

Title Transfer and Indemnity:

Sections 10.3 and 10.4 of the EEI Master Agreement shall apply only to Power Products. With respect to RECs, title transfers from Seller to Buyer upon the completion of both Delivery and payment for the RECs.

Mutual Representations and Warranties. During the Delivery Term, each Party represents and warrants to the other that: (i) it is an "eligible commercial entity" and an "eligible contract participant" within the meaning of United States Commodity Exchange Act §§1a(11) and 1a(12), respectively, and this Transaction has been subject to individual negotiation by the Parties.

SPECIAL PROVISIONS:

(1) Green Attributes: Seller hereby provides and conveys all Green Attributes associated with all electricity generation from the Project to Buyer as part of the Product being delivered. Seller represents and warrants that Seller holds the rights to all Green Attributes from the Project, and Seller agrees to convey and hereby conveys all such Green Attributes to Buyer as included in the delivery of the Product from the Project. [STC 2 - RECs and Green Attributes, Non-Modifiable. D.08-04-009 (3.2)].

(2) Transfer of Renewable Energy Credits: Seller and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement the renewable energy credits transferred to Buyer conform to the definition and attributes required for compliance with the California Renewables Portfolio Standard, as set forth in California Public Utilities Commission Decision 08-08-028, and as may be modified by subsequent decision of the California Public Utilities Commission or by subsequent legislation. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. [STC REC-1, Non-modifiable D.11-01-025].

(3) Tracking of RECs in WREGIS: Seller warrants that all necessary steps to allow the Renewable Energy Credits transferred to Buyer to be tracked in the Western Renewable Energy Generation Information System will be taken prior to the first delivery under the contract. [STC REC-2, Non-modifiable. D.11-01-025].

(4) RECs Settlement: During the Delivery Term, each Party, at its own cost and expense, shall maintain its registration with WREGIS. Each Party shall, at its sole expense, use WREGIS as required pursuant to the WREGIS Operating Rules to deliver and convey (in the case of Seller) and receive/accept (in the case of Buyer) RECs in accordance with WREGIS reporting protocols and WREGIS Operating Rules. Seller shall, at its sole cost and expense, take all commercially reasonable actions and execute documents or instruments necessary to ensure that the RECs to be sold hereunder from the Project can be transferred to Buyer utilizing WREGIS and that the transfer of WREGIS Certificates shall represent the RECs attributable to or associated with such Green Attributes from the Project. Buyer warrants that all necessary steps to allow the RECs transferred from Seller to be tracked in WREGIS will be taken prior to the first delivery under the contract.

(5) Eligibility: Seller, and, if applicable, its successors, represents and warrants that throughout the Delivery Term of this Agreement that: (i) the Project qualifies and is certified by the CEC as an Eligible Renewable Energy Resource ("ERR") as such term is defined in Public Utilities Code Section 399.12 or Section 399.16; and (ii) the Project's output delivered to Buyer qualifies under the requirements of the California Renewables Portfolio Standard. To the extent a change in law occurs after execution of this Agreement that causes this representation and warranty to be materially false or misleading, it shall not be an Event of Default if Seller has used commercially reasonable efforts to comply with such change in law. [STC 6, Non-Modifiable D.08-04-009];

(6) Additional Representations and Warranties of Seller.

(i) Seller has not sold the Product or any Green Attributes of the Product to be transferred to Buyer to any other person or entity;

(ii) each REC meets the specifications set forth herein;

(iii) All rights, title and interest in and to the Product are transferred free and clear of any taxes or security interests except for any right or interest by any entity claiming through Buyer.

(7) Payments for RECs. Seller shall invoice Purchaser for the RECs after the WREGIS Certificates for such RECS have been properly transferred to Purchaser's WREGIS account in accordance with the rules and regulations of WREGIS. Purchaser shall pay the RECs Contract Price for the WREGIS Certificates transferred to Purchaser's WREGIS Account not later than ten (10) Business Days following receipt of Seller's invoice subsequent to the transfer of the RECs.

(8) Regulatory: The Parties intend the rates, terms and conditions of service specified in this Confirmation to remain fixed throughout the Delivery Term of this Confirmation regardless of any changes in underlying costs that would justify a change in rates under traditional cost of service principles. Neither Party shall unilaterally seek to obtain from FERC any relief changing the rate, charge, classification, or other term or condition of this Confirmation, notwithstanding any subsequent changes in Applicable Law, its costs of service or market conditions that may occur.

(9) Governing Law. For purposes of this Confirmation Article 10.6, Governing Law, of the EEI Master Agreement is amended by inserting at the end thereof the following: "Notwithstanding the foregoing, this Agreement and the rights and duties of the Parties hereunder shall be governed by and construed, enforced and performed in accordance with the laws of the state of California, without regard to principles of conflicts of law. To the extent enforceable at such time, each Party waives its respective right to any jury trial with respect to any litigation arising under or in connection with this Agreement. [STC 17, Applicable Law, Non-Modifiable D.08-04-009].

(10) Liquidated Damages. For purposes of this Confirmation only, Article 4 of the EEI Master Agreement is amended by inserting at the end thereof the following: In lieu of and not in addition to the damages provided in this Article 4, in the event that Seller's failure to deliver is due to DSO 216, Buyer's damages shall be limited to the lower of Buyer's actual loss or two times the Contract Price for the affected Contract Quantity.

(11) RPS Confidentiality. Either Party shall be permitted to disclose the following terms with respect to such Transaction: Party names, resource type, delivery term, project location, and project capacity.

DEFINITIONS / INTERPRETATIONS: For purposes of this Confirmation, the following definitions and rules of interpretations shall apply:

"Applicable Law" means all legally binding constitutions, treaties, statutes, laws, ordinances, rules, regulations, orders, interpretations, permits, judgments, decrees, injunctions, writs and orders of any Governmental Authority or arbitrator that apply to the Applicable Program or any one or both of the Parties or the terms hereof.

"California Program", "California Renewables Portfolio Standard" or "California RPS" means the renewable energy program and policies, codified in California Public Utilities Code Sections 399.11 through 399.20 and California Public Resources Code Sections 25740 through 25751, as such provisions are amended or supplemented from time to time.

"CEC" means the California Energy Commission or its regulatory successor.

"CEC Certification" means, if applicable, the certification of the renewable resource by the California Energy Commission as specified in the Renewables Portfolio Standard Eligibility Guidebook as eligible toward meeting the state's Renewables Portfolio Standard pursuant to Public Utilities Code Sections 399.11, et seq. and Public Resources Code Section 25741.

"CPUC" means the California Public Utilities Commission or its regulatory successor.

"Green Attributes" means any and all credits, benefits, emissions reductions, offsets, and allowances, howsoever entitled, attributable to the generation from the Project, and its avoided emission of pollutants. Green Attributes include but are not limited to RECs, as well as: (1) any avoided emission of pollutants to the air, soil or water such as sulfur oxides (SOx), nitrogen oxides (NOx), carbon monoxide (CO) and other pollutants; (2) any avoided emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide, hydrofluorocarbons, perfluorocarbons, sulfur hexafluoride and other greenhouse gases (GHGs) that have been determined by the United Nations Intergovernmental Panel on Climate Change, or otherwise by law, to contribute to the actual or potential threat of altering the Earth's climate by trapping heat in the atmosphere;[1] (3) the reporting rights to these avoided emissions, such as Green Tag Reporting Rights. Green Tag Reporting Rights are the right of a Green Tag Buyer to report the ownership of accumulated Green Tags in compliance with federal or state law, if applicable, and to a federal or state agency or any other party at the Green Tag Buyer's discretion, and include without limitation those Green Tag Reporting Rights accruing under Section 1605(b) of The Energy Policy Act of 1992 and any present or future federal, state, or local law, regulation or bill, and international or foreign emissions trading program. Green Tags are accumulated on a MWh basis and one Green Tag represents the Green Attributes associated with one (1) MWh of Energy. Green Attributes do not include (i) any energy, capacity, reliability or other power attributes from the Project, (ii) production tax credits associated with the construction or operation of the Project and other financial incentives in the form of credits, reductions, or allowances associated with the Project that are applicable to a state or federal income taxation obligation, (iii) fuel-related subsidies or "tipping fees" that may be paid to Seller to accept certain fuels, or local subsidies received by the generator for the destruction of particular preexisting pollutants or the promotion of local environmental benefits, or (iv) emission reduction credits encumbered or used by the Project for compliance with local, state, or federal operating and/or air quality permits. If the Project is a biomass or biogas facility and Seller receives any tradable Green Attributes based on the greenhouse gas reduction benefits or other emission offsets attributed to its fuel usage, it shall provide Buyer with sufficient Green Attributes to ensure that there are zero net emissions associated with the production of electricity from the Project. [STC 2, RECs and Green Attributes, Non-Modifiable.]

"Governmental Authority" means any international, national, federal, provincial, state, municipal, county, regional or local government, administrative, judicial or regulatory entity operating under any Applicable Laws and includes any department, commission, bureau, board, administrative agency or regulatory body of any government.

"HE" means the hour ending.

"PPT" means Pacific prevailing time.

"REC" or "Renewable Energy Credit" means the right to claim Green Attributes attributable to the generation of electric energy from renewable energy resources. RECs are measured in one megawatt-hour increments and evidenced by a WREGIS Certificate. A REC includes all Green Attributes arising as a result of the generation of electricity associated with the REC.

"STC" stands for Standard Terms and Conditions of the CPUC relating to purchase and sales of Green Attributes.

"Vintage" means the period in which the REC was or will be created by the Project.

"WECC" means the Western Electricity Coordinating Council or its successor organizations.

"WREGIS" means the Western Renewable Energy Generation Information System.

"WREGIS Certificates" has the same meaning as "Certificate" as defined by WREGIS in the WREGIS Operating Rules and are designated as eligible for complying with the California Renewables Portfolio Standard.

"WREGIS Operating Rules" means those operating rules and requirements adopted by WREGIS as of June 4, 2007, as subsequently amended, supplemented or replaced (in whole or in part) from time to time.

Please confirm that the terms and conditions stated herein accurately reflect the agreement reached by Buyer and Seller by signing and returning by facsimile to Seller at (858) 320-2674.

[SIGNATURE PAGE FOLLOWS]

[1] Avoided emissions may or may not have any value for GHG compliance purposes. Although avoided emissions are included in the list of Green Attributes, this inclusion does not create any right to use those avoided emissions to comply with any GHG regulatory program.

IN WITNESS WHEREOF, the Parties have signed this Confirmation effective as of the Effective Date.

The Stockton Port District	Shell Energy North America (US), L.P.
By:	By:
Name: Steve Eggebrecht	Name: BETH BOWMAN
Title: Deputy Port Director	Title: Sr. Vice President